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June 15, 2015

Via Electronic Filing and US Mail

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 1088
SALEM OR 97308-1088

RE: Docket No. UE 294 – In the Matter of
PORTLAND GENERAL ELECTRIC COMPANY,
Request for a General Rate Revision.

Enclosed for filing is Public Utility Commission Staff Opening Testimony.

Exhibits 207, 402, 403 and 404 are confidential and will be mailed separately to parties who have signed Protective Order No. 15-036.

A copy of UE 294 Service List and Certificate of Service are included with this filing.

/s/ Kay Barnes
Filing on Behalf of Public Utility Commission Staff
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CASE: UE 294
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

June 15, 2015

Q. Please state your name, occupation, and business address.

A. My name is Matt Muldoon. I am a Senior Economist for the Public Utility Commission of Oregon (Commission or OPUC). My business address is: 3930 Fairview Industrial Dr. SE, Salem, OR 97302-1166.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement can be found in Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. I am responsible for four issues generally regarding Cost of Capital (CoC) in this docket:

1. Capital Structure,
2. Cost of Common Equity, also known as Return on Equity (ROE),
3. Cost of Long-Term (LT) Debt, and
4. Allowance for Funds Used During Construction (AFUDC).

Q. What is your summary recommendation regarding ROE?

A. I recommend PGE's ROE be reduced from the 9.68 percent set in PGE's previous rate case to 9.16 percent.

ISSUE 1 – CAPITAL STRUCTURE

Q. What is the basis for your recommendation for 50 percent debt/equity, capital structure?

A. I have four reasons for supporting this capital structure:

1. PGE has consistently presented this target capital structure to investors, to the Security and Exchange Commission (SEC) and to rating agencies

since PGE refloated its current series of common stock after the demise of Enron;

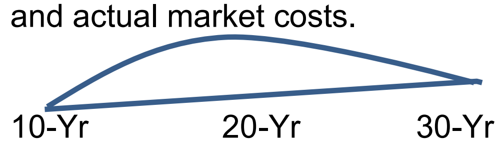
2. PGE can achieve this 50/50 target through current proposed and Commission authorized issuances of LT debt and its equity forward;
3. This target is within the range of capital structures that optimizes the Company's financial performance as balanced against the risk of leverage; and
4. This is the same capital structure adopted for the last several rate cases by the Commission for PGE.

<u>ISSUE 2 – COST OF COMMON EQUITY (ROE)</u>

Q. PGE is requesting an ROE of 9.9 percent. This recommendation is based in part on the Company's ROE witness Dr. Bente Villadsen of The Brattle Group's multistage discounted cash flow models estimating a 9.8 and 9.10 percent ROE. What are the bases for the difference between the Company's requested ROE and your recommended 9.16 percent ROE beyond GDP Growth differences?

A. There are several reasons, but primarily because the Company:

- Uses 20-year US Treasury (UST) bond values as a benchmark for spreads. Academic and market analysis typically uses 10-year and 30-year values. Use of the 20-year data inflates textbook understandings and actual market costs.



- Shortens declining future data series. PGE selects higher values by using data from five years instead of 30 years into the future for long-term third stage growth rate of discounted cash flow (DCF) modeling.

PGE also shortens the estimate window, which conflates medium immediate-term Blue Chip values to the higher five year values.

- Emphasizes historical methods with tails back to higher inputs. For example: A spread of bonds over risk free rates extrapolating five years of data forward would no longer reach back to the market disruption of 2008. Current and common practice is to use a five-year spread, which now phases out the 2008 downturn. In Exhibit PGE/1100, Villadsen/42, PGE uses a three pronged approach that inflates results. First PGE uses a 6.37 percent risk premium, relying on a 20-year UST bond rate. Second, PGE uses UST projections leaning into 2017, which maximize the time value of uncertainty in market forwards. Relying on the 1997 to 2014 period rather than a typical five-year history as shown in Value Line (VL), lets PGE continue to incorporate the 2008 to 2010 and world trade center disruptions. The result is a 10.7 percent cost of equity estimate rather than about a 9.2 percent.
- Overstates required Hamada adjustments. PGE uses 10 years of historical book capital structure that enlarges the effect of the Hamada adjustment for disparate leverage. Corrected to typical market use, PGE's peer group on average merits no adjustment. PGE here also reaches back in time avoiding forward looking information even though it is available via VL.
- Relies on positive near term projections that were not realized. For example, a year ago many experts expected Q1 2015 GDP to be more positive. Now that we are here, it looks like another disappointment.[1] This is not a technical error on PGE's part. Rather Staff has the advantage of later opening testimony when more current information was available.
- Uses a less closely screened cohort of peer utilities including companies that the Edison Electric Institute (EEI) determines are 50 percent to 79 percent regulated on top of Staff's 80 percent regulated assets cutoff.[2]
- In Exhibit PGE/1103, Villadsen/2 PGE explains two methods that increase required returns. First, instead of performing CAPM calculations using 10- or 30-year UST as the current forward looking risk free benchmark, PGE shifts upward its UST risk free value already inflated as the 20-year rate, a rate seldom actually used by academics or market analysts because it is a poor value and thinly traded – unrepresentative. Then PGE adds the difference between 20 year and 10 year current relatively high spread peculiarly and uniquely on top of

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[1] See the article, "Recovery Stumbles Yet Again" by Josh Mitchell in the May 30, 2015, print edition of the Wall Street Journal (WSJ).

[2] See UE 294/PGE/1100, Villadsen/33, at lines 4-5.

the 20 year values. This unusual manipulation increases outcomes by 1 percent, before other adjustments.

- PGE relies on higher than reasonable Market Risk Premiums (MRP). PGE creates its own estimated risk-free rate, avoiding historically low risk free rates seen now. Dr. Villadsen states that she cannot believe that today's MRP could be less than the historical MRP.
- PGE reverses UST yield trends and fails to address $1 trillion Euro quantitative easing. In a time when German five-year bonds have had a negative return, PGE says that investors are more risk averse but fails to point out that the relative safe and more attractive investments are PGE's dividend-bearing stock and bonds.[3]
- The next method that boosts outcomes is the use of Dr. Roger Morin's "Empirical CAPM" or (ECAPM). Were no mathematical steroids used in the basic CAPM model, CAPM would return a lower required ROE than Staff recommends. ECAPM (a method not commonly used by finance academics and professionals) presumes that the security market line could be pivoted at a designated point until a reasonable result is obtained. The argument is that a properly pivoted CAPM model will correct for CAPM's flaws. Essentially this is a method that augments CAPM ROE by a minimum of 50 bps.
- Injects after-tax calculations in comparison with pretax constructs.

Q. How is your testimony organized?

A. My testimony is organized as follows:

3 See "Why Dividend-Paying Stocks Are a Retiree's Best Friend" by Jonathan Clements in the May 30, 2015, print edition of the WSJ. Therein, Mr. Clements points out that with bond yields so low, wise investors are replacing some bond holdings with a diverse portfolio of reliable dividend paying stocks with an aggregate dividend yield of about three percent.

Q. Did you prepare exhibits in support of your opening testimony?

A. Yes. I prepared the following exhibits:

Staff/202 .... Staff Peer Screening

Staff/203 .... Staff Three Stage DCF Modeling

Staff/204 .... Staff Synthetic Forward Curve TIPS Analysis

Staff/205 .... Staff Historical GDP Analysis with BEA Data

Staff/206 .... Representative GPD Growth Projections

Staff/207 ....**CONFIDENTIAL** – Cost of LT Debt Table

Staff/208 .... PGE Depiction of Rate Base Expansion to Investors

Staff/209 .... Value Line (VL) Electric Utility Profiles

Staff/210 .... Moody's Sector In-Depth – US Regulated Utilities

Staff/211 .... Frequency of Peer General Rate Case Filings

Q. Does Staff's recommended ROE meet appropriate standards?

A. Yes. Assuming the other cost elements of the rate case are also well founded, the 9.16 percent ROE I recommend meets the *Hope* and *Bluefield* standards, as well as the requirements of Oregon Revised Statute (ORS) 756.040. My recommendations are consistent with establishing "fair and reasonable rates" that are both "commensurate with the return on investments in other enterprises having corresponding risks" and "sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[4]

Q. Are these the same standards discussed in PGE's testimony?

A. Yes. Staff and PGE apply the same legal standards. However, PGE and Staff disagree on what ROE is commensurate with that of other utilities and other investment opportunities with risk exposure similar to PGE's. When investors' expected rate of return is measured using a reasonable expectation of long-term growth, and when risk is measured using an appropriate peer group of utilities, the resulting ROE is within the range recommended by Staff.

WHAT IS NEW IN THIS RATE CASE?

Q. What is new in this third general rate case that PGE has filed in as many years?

A. Two primary considerations arise in this rate case for the Company. First, this is the Company's third consecutive annual rate case. The two prior general rate cases were in Docket No. UE 283 and Docket No. UE 262. In Docket No. UE 283 (PGE's 2014 General Rate Case), PGE requested and was granted two tariff riders for recovering the costs of two major generation

[4] *See* ORS 756.040(1) (a) and (b).

capital projects: Port Westward II of up to approximately $300 million of capital costs and Tucannon River Wind Farm of approximately up to $500 million of capital costs.[5]

Similarly, in this case, PGE seeks a tariff rider to include a new plant, Carty, which is scheduled to be online late in the first half of the 2016 test year. Multiple consecutive annual rate cases and prompt cost recognition of new generation, transmission and substation facilities, including Carty, reduce risk in the form of reduced regulatory lag and greater known certainty of cost recovery.

This reduction in risk and regulatory lag merits a lower point ROE from within a range of reasonable ROEs. For example: the Maryland Commission recently found that a company that engages in consecutive annual filings merited a lower than top end of range ROE due to the reduced risk.[6]

Q. Do Staff's peer utilities in its ROE modeling file rate cases less frequently?

A. Yes, in the last five years, none of Staff's peer utilities has filed three consecutive annual general rate cases. Please see Exhibit Staff/211.

Q. What is the second consideration, not addressed in prior rate cases?

A. A broad, consensus of federal government agencies, economists and referent experts now project substantially lower long-term growth in US Gross Domestic Product (GDP). Paired with another broad consensus that growth

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5 Order No. 14-422 at 7-8.

6 Public Service Commission of Maryland, Order No. 85374, Case No. 9299, at 78 (February 22, 2013).

in US electricity sales will be less than the rate of GDP growth, this trend has serious implications not yet considered when Commission Order No. 14-422 was issued in the Company's last general rate case.

Q. What is the primary implication of your second consideration?

A. All else held constant in Staff's current modeling, the reduction in projected long-term GPD growth translates into a 31 basis point downward shift in the range of reasonable ROEs for PGE.

Q. Could all these experts be wrong and might this be a temporary case of broad group-think based on various international headwinds and temporary economic setbacks?

A. That is unlikely. US worker productivity has been declining. Fewer children have been born annually since 2008. US immigration policy still awaits overhaul. American average age is increasing. Europe, Japan and China are undertaking huge stimulus programs. ... And so on.

It is possible that the definitive lack of a "bounce" in growth after the recession and so many negative bits of economic news have caused academic, business, and federal economic experts to be temporarily reluctant to predict a long-run return to the historical average annual American growth trends between 1983 and 2007 of 3.2 percent.[7]

Q. How do you recommend the Commission address this economic decline or transitional mark?

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[7] See the Wall Street Journal Article, "In a Slow Economy, Negative Quarters Shouldn't Surprise" by Greg Ip published in the print edition on May 28, 2015. This article emphasized two drivers of low GDP growth: 1) Aging population and shrinking labor force, and 2) Lower productivity – output per worker.

A. Staff's analysis shows multiple growth rate levels. Staff recommends a 9.16 ROE that is in the midpoint of a reasonable range of ROEs, allowing for further corroboration of a substantial downshift in American growth expectations. This is a conservative point ROE given the available evidence at this moment that supports a slower long term growth rate. Moreover, Staff's assessment does not rely on lower modeling results associated with many of the Company's suggested peers, and instead finds that Staff screened, mid-capitalization (Mid-Cap), electric utilities closest to PGE's size best fit investor expectations. Please see Exhibit Staff/203.

Q. Are current economic conditions a "Goldilocks Moment" for Oregon Public Utility Commission (OPUC) jurisdictional energy utilities?

A. It will be easier to answer that question in historical hindsight. However, there are three good reasons to believe financial conditions are near optimal now for these utilities.

Q. What is the first of these reasons?

A. The first factor is insulation from global uncertainty. For example, Moody's points out that nearly all of regulated continental US electric utility revenues and operating expenses are denominated in US dollars providing a natural hedge against sustained US dollar appreciation.

Q. What is the second of these reasons?

A. Next, continued low interest rates facilitate strategic investment to meet long-run utility needs, while making predictable dividend-paying equities more attractive to investors than global cyclical firms.

Q. And what is the third element?

A. A mix of negative and positive economic news extends the investor "flight to quality / safety" freezing current conditions just right for regulated investor owned utilities.[8]

Q. Are you suggesting the Commission should consider whether current economic conditions make jurisdictional utilities less risky than other potential investments?

A. Yes.

Q. Further are you suggesting utilities that file multiple consecutive annual general rate cases and receive expedited cost recovery for new facilities face even less risk?

A. Yes.

Q. To recap, are the two new elements since the last PGE general rate case: A) Consideration of a marked downturn in projected US long-term GPD growth, and B) Consideration whether PGE itself faces reduced risk even over prevailing beneficial economic conditions for US regulated utilities?

A. Yes. Enough has changed since PGE's last general rate case, that the Commission may want to reduce PGE's point ROE substantially, depending

8 See "Economists' Forecast: Here We Grow Again" by Kathleen Madigan, and "Why the Economy and the Fed Keep Getting Knocked Off Track" by Jon Hilsenrath in the print edition of the Wall Street Journal (WSJ) for May 15, 2015. Articles like the above and "Workers' "Productivity Declines Again" by Jeffrey Sparshott in the May 7, 2015, WSJ periodically deflate investor expectations for a return to pre-2008 economic conditions.

in part on the Commission's confidence in current consensus economic forecasts of declining long-term GDP growth.

OVERVIEW OF ROE POSITIONS

Q. Did you prepare tables showing current, PGE proposed and Staff proposed overall cost of capital?

A. Yes, the following tables provide that information.

Table 1

Currently Authorized (UE 283 Order No. 14-422)			PGE
Component	**Percent of Total**	**Cost**	**Weighted Average**
Long Term Debt	50.00%	5.443%	2.722%
Preferred Stock	0.00%		0.000%
Common Stock	50.00%	9.680%	4.840%
	100.00%		**7.562%**

Table 2

PGE Proposed (UE 294)			(as filed)	
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long Term Debt	50.00%	**5.433%**	2.717%	
Preferred Stock	0.00%		0.000%	
Common Stock	50.00%	**9.900%**	4.950%	
	100.00%		**7.667%**	0.105%

Table 3

Staff - June 4, 2015 – UE 294 Recommended			TESTIMONY	
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long Term Debt *	50.000%	**5.235%**	2.618%	
Preferred Stock	0.000%		0.000%	
Common Stock	50.000%	**9.160%**	4.580%	
	100.00%		**7.198%**	**-0.364%**

* Reflects Average of Bloomberg Daily Forwards for Mo. of Apr. 2015
(LT Debt will be Updated in Reply Testimony)

Q. Describe the analysis underlying Staff's ROE recommendation.

A. I continue to rely primarily on two different multistage DCF models,[9] applied using a cohort group of peer utilities, to estimate the expected return on common equity required by PGE investors. I compare the results of my DCF analysis with national historical electric utilities' authorized ROE values as a check on the reasonableness of my ROE estimates. I also input parameters from some of the models used by Dr. Villadsen into Staff's models and contrast the analytic outputs with Dr. Villadsen's results and with results from my two DCF models using Staff's inputs.

Q. What is a Discounted Cash Flow (DCF) model?

A. A DCF model estimates the cost of equity by determining the present value of the future cash flows that investors expect to receive from holding common stock. The current stock price is assumed to reflect investors' expectations for the stock, including future dividends and price appreciation.

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[9] *See*, in Docket No. UE 115, the Commission's discussion of multistage versus single-stage DCF models in Order No. 01-777 at page 27.

The return on equity under the DCF model is the rate that equates the current stock price and expected cash flows to investors.[10] A DCF model has three primary components: a current stock price, an expected dividend, and an expected growth rate in dividends.[11]

Q. Describe the two DCF models that you used.

A. My first model is a conventional three-stage Discounted Dividend Model, which Staff denotes as a “30-year Three-stage Discounted Dividend Model with Terminal Valuation based on Growing Perpetuity” (hereinafter referred to as “Model X“). My second model is the “30-year Three-stage Discounted Dividend Model with Terminal Valuation Based on P/E Ratio” (hereinafter referred to as “Model Y“).

Both models require, for each proxy company analyzed by Staff, a “current” market price per share of common stock, estimates of dividends per share to be received in the years 2015 through 2019, annual rates of dividend growth from 2020 through 2024, and a long-term growth rate applicable to dividends beyond 2024.

The three stages of the models are: 1) 2015-2019, where I use Value Line’s forecasts of dividends per share for each company; 2) 2019-2024, wherein the rate of dividend growth converges from the average rate over the 2015-2019 period to the growth rate in of the third stage; which is, 3) 2025-2044.

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10 Order No. 01-777 at 26.

11 Order No. 07-015 at 32.

Model X includes a terminal value calculation, in which I assume dividends per share grown indefinitely at the rate of growth in Stage 3 ("growing perpetuity"). In contrast Model Y terminates in a sale of stock wherein the price is determined by my escalated price/earnings (P/E) ratio.

Q. Why did you use five years for Stages One and Two, and about 20 years for Stage Three?

A. I presume a 30 year horizon is relevant for investors. This is consistent with long standing Staff practices including those of former Staff member, Steve Storm in the NW Natural general rate case of Docket No. UG 221, which the Commission adopted in Order No. 12-408. This time frame allows for investor consideration of 30-year US Treasury Long Bond and other alternate investment opportunities. I use five years for Stage One as that is the timeframe for which VL estimates of future dividends are available. I use five years for Stage Two as that seems a reasonable length of time for individual companies' dividend growth rates that are materially different from the growth rate used in Stage Three (and common to all companies) to converge to a LT dividend growth rate more representative of all electric utilities. I discuss the mechanics of this convergence below. I use 15 to 20 years for Stage Three, corresponding to forward projections from federal sources, and calculate a terminal valuation for the sale of the Company's stock in 2043.

Q. How do you address dividend timing?

A. Each model uses two sets of calculations that differ in the assumed timing of dividend receipt. One set of calculations is based on the standard assumption that the investor receives dividends at the end of each period.

The second set of calculations assumes the investor receives dividends at the beginning of each period. Each model averages the unadjusted ROE values[12] produced with each set of calculations for each peer utility. This approach more closely replicates the "real world" quarterly receipt of dividends by investors; i.e., it takes into account the time value of money.

Q. What accounts for differences in peer capital structures?

A. Each model employs the Hamada equation to calculate an adjustment for differences in capital structure between each peer utility and the PGE proposed and Staff-assumed capital structure for Portland General Electric.[13] When few peer utilities are available, the Hamada equation offers greater material adjustments.

In this case, where many peer electric utilities are available, Staff's screening yields peers sufficiently close to the Company's capital structure that the Hamada equation adjustments are less dramatic.

Q. What price do you use for each peer utility's stock?

A. I use the average of closing prices for each utility from the first trading day in January, February, and March 2015.

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12 The technical term for each of these estimates is the "internal rate of return," or IRR.

13 Staff describes this adjustment in recent cost of capital testimony. See, as an example, Staff's description in Docket No. UE 233 Exhibit Staff/800, Storm/54 through Storm/57.

Q. Did you review the impact of using prices from any other day of these months?

A. No.

Q. How do Staff's two DCF models differ?

A. Model X uses the calculation of a growing perpetuity as part of the terminal valuation in 2043. This may be the most common approach used in multistage DCF models.

Model Y uses the current price-earnings (P/E) ratio[14] multiplied by the estimated earnings per share (EPS) in 2043, which establishes the stock's "selling price" in 2043 for terminal valuation. I estimate the 2043 EPS analogously with methods used to estimate the 2043 dividend in both models; i.e., based on VL estimates to which multiple growth rates are sequentially applied.

Q. What is the purpose of Model Y?

A. I followed Staff's practice in recent rate cases of including this model as a method by which to incorporate the fact that most companies have estimates of future EPS and future dividends growing at different rates. Utilizing EPS that grows on a separate trajectory than dividends is the foundation for an alternative means of terminal valuation.[15]

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[14] "Current" in this context means the price obtained, as previously described, divided by Value Line's estimated earnings per share (EPS); i.e., it is a forward P/E, not an historical P/E.

[15] Please note that the approach used in this second model is not the same as using a singular estimate of the growth rate in EPS as the growth rate in dividends.

PEER SCREEN

Q. How did you select comparable companies (peers) to estimate PGE's ROE?

A. I used companies that meet the following criteria as peer utilities to the regulated electric utility activities of Portland General Electric:

1. Covered by VL as an Electric Utility;
2. Forecasted by VL to have Positive Dividend Growth;
3. S&P LT Issuer Credit Rating from S&P of BB+ to BBB+;
4. No Decline in Annual Dividend in Last Five Years Based on SNL;
5. Has 80 percent or greater Regulated Assets *A*ccording to EEI;
6. Has 45 percent to 55 percent LT Debt in VL Capital Structure; and
7. Has No Recent Merger and Acquisition Activity.

Q. Why do you eliminate companies that are not forecasted to have positive dividend growth?

A. There is evidence that investors find common stock of dividend-cutting utilities less attractive. The FPL Group's Florida Power and Light and Niagara Mohawk Power Corporation stock prices declined sharply after dividend cuts.[16] These real world findings are consistent with Staff's screening out electric utilities that have recently cut dividends.

Q. What cohort of companies resulted from your screens?

A. Please see Staff/202 Muldoon/1-2 for detailed Staff screens and also for a table that shows the list of peer utilities obtained from Staff screens and those

[16] An example of investor reaction to dividend cuts is found in The New York Times article, "Niagara Mohawk Stock Dives After Dividend Suspension", published January 25, 1996.

obtained from PGE screens in the current rate case, as well as those obtained by both Staff and PGE in Docket Nos. UE 262 and UE 283.

SENSITIVITY ANALYSIS

Q. Did you perform sensitivities that evaluated the impact of peer selection in this case?

A. Yes, I also ran each of Staff's models imposing a Mid-Cap size screen of between two and ten billion dollars capitalization reflecting PGE's financial size. This Mid-Cap sensitivity analysis increased my top reasonable range of ROEs by an additional 49 basis points over that obtained using the Company's peer utilities in Staff's three-stage DCF modeling.

Q. How does Staff apply informed judgement to its modeling?

A. Staff examined its full range of modeling results from 8.27 percent to 9.57 percent after all adjustments. Within that range Staff determined that 8.75 percent to 9.57 percent, reflecting mid-cap size capitalization like PGE was the best fit to capture investor expectations of PGE performance. Please note that this range still incorporates the highest growth from PGE's last general rate case.

Q. Does Staff's removal of the lower end of modeling results from 8.27 percent to 8.74 percent suggest Staff's results are reasonable and conservative?

A. Yes, this is a representative indicator that Staff recommendations are balanced, fact based and reasonable.

Q. Does the running of these sensitivities replace or modify Staff's primary screening methods?

A. No. However, the results of my sensitivity analyses inform the Commission. Utility capitalization size is a selection metric for investors and can affect investor expectations. By performing the Mid-Cap sensitivity, Staff reasonably addresses firm size.

Q. Did the sensitivity of processing Company peer utilities through Staff's three-stage DCF modeling generate useful information?

A. No. The results from Staff's peer utilities and the results from the Mid-Cap sensitivity group bracketed and included the set of results using the Company's peers. Staff higher Mid-Cap results better fit PGE's prospects than lower modeling results associated with many Company proposed peers.

GROWTH RATES

Q. What is the single most important element of discounted dividend or DCF models when used to estimate investors' required ROE?

A. The estimated rate of growth of future dividends. I refer specifically to the singular growth rate for constant growth DCF models and the long-term growth rate for multistage DCF models such as those I use.

Q. What long-term growth rates do you use in the two DCF models? [17]

[17] Methods used here related to GDP-based growth rates are similar, if not identical to methods Staff has used in past proceedings. See, as an example, Staff's discussion of these methods and, to a limited extent, their conceptual underpinnings in Docket No. UE 233, at Exhibit Staff/800, Storm/46 line through Storm/52 line 14.

A. I used four different long-term growth rates, with different methods employed in developing each.

The first method uses a 50 percent weight applied to the average annual growth rate resulting from estimates of long-term Gross Domestic Product (GDP) by the EIA, the OMB, and the CBO, with each receiving one-third of the 50 percent weight.[18] The remaining 50 percent is the average annual historical real GDP growth rate, established using regression analysis, for the period 1980 through 2014,[19] to which I apply the TIPS inflation forecast.

The second long-term growth rate for Stage 3 dividends is a control reflecting PGE's Blue Chip & OMB growth rate.

The third Stage 3 annual growth rate, which I use primarily for illustrative purposes, is the Indiana / Top-10 Blue Chip most recent optimistic upper book-end projection as of April 2015.

The fourth final stage growth rate is the Company's Top-10 Blue Chip most optimistic upper book-end projection of growth from PGE's prior general rate case in Docket No. UE 283.

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18 The EIA is the Energy Information Administration within the US Department of Energy, OMB is the Office of Management and Budget, and CBO is the Congressional Budget Office. EIA and OMB's estimates are of nominal GDP. I applied to CBO's estimate of real GDP an inflation rate for the relevant timeframe developed using the Treasury Inflation-Protected Securities (TIPS) method described by Staff in testimony in multiple recent general rate case proceedings. See, as an example, in Docket No. UE 233 Exhibit Staff/800, Storm/50 line 4 through Storm/51 line 3. The TIPS forecast of annual inflation over the relevant Stage 3 timeframe is 2.12 percent, based on an average of interest rates for each of the months of January 2014, February 2014, and March 2014. It may be useful to think of the TIPS inflation rate forecast as a forward curve of dollars; i.e., market-based estimates of what a dollar will be worth in the future.

19 Staff discussed this approach in recent Staff cost of equity testimony in several rate case proceedings. See, as an example, in Docket No. UE 233 Exhibits Staff/800, Storm/46, line 15 through Storm/50 line 3.

Q. What are the values for these growth rates?

A. Please see Tables 4-A and 4-B below.

Table 4-A
GDP Growth Rates

Stage 3 – Long-Term Annual Dividend Growth Rate					
Component	**Real Rate**	**TIPS Inflation Forecast**	**Nominal Rate**	**Weight**	**Weighted Rate**
EIA 2014 Placeholder	*2.40%*	**2.12%**	*4.57%*	16.70%	0.76%
OMB - White House 2016 Budget			**4.30%**	16.70%	0.72%
CBO			**4.20%**	16.70%	0.70%
Historical 1980 – 2014	**2.87%**	**2.12%**	5.05%	50.0%	2.53%
Composite				100%	**4.71%**
Historical 1980 – 2014 Q4			5.05%	100.0%	**5.05%**
Indiana U – Kelley 2018-35 Ctr Econometric Research	**2.90%**	**2.12%**	5.08%	100.0%	**5.08%**
Blue Chip* – Top 10% 2019 Values	**2.90%**	**2.12%**	5.08%	100.0%	**5.08%**
Blue Chip – Average	**2.40%**	**2.12%**	4.57%	100.0%	**4.57%**
Blue Chip – Bottom 10%	**1.90%**	**2.12%**	4.06%	100.0%	**4.06%**
PGE "Blue Chip" 2015 thru 2019 Average	**PGE/1101 Villadsen P3**		4.70%	100.0%	**4.70%**
PGE "Blue Chip & OMB"	**PGE/1101 Villadsen P4**		4.80%	100.0%	**4.80%**
Blue Chip* – Top 10% 2021-2025 Values	**2.70%**	**2.12%**	4.88%	100.0%	**4.88%**
Blue Chip – Average	**2.30%**	**2.12%**	4.47%	100.0%	**4.47%**
Blue Chip – Bottom 10%	**2.00%**	**2.12%**	4.16%	100.0%	**4.16%**
Blue Chip* – Top 10% 2021-2025 Values	**Nominal**		**5.00%**	100.0%	**5.00%**
Blue Chip – Average			**4.40%**	100.0%	**4.40%**
Blue Chip – Bottom 10%			**3.90%**	100.0%	**3.90%**

Q. Briefly explain why PGE's long-term growth values may not be appropriate.

A. PGE draws its long-term growth values as the average value for 2015-2019. In contrast use of 2021 to 2025 Average Blue Chip Values drops growth by 23 to 30 basis points depending on calculation method. PGE's reliance on nearer term numbers diminished exposure to a precipitous drop in projections of long-term GDP growth.

Q. How deep and how universal are these expectations of diminished US long-term GDP growth?

A. Even the most optimistic in Top-Ten Blue Chip and academic experts no longer project upbeat US growth. See Table 4-B below:

Table 4-B
One Year Change in GDP Growth Projections

Growth Trends	UE 294 Now	UE 283 Prior	Difference
Tips Inflation Forecast	2.12%	2.35%	**-0.23%**
EIA	4.57%	4.89%	**-0.32%**
OMB	4.30%	4.61%	**-0.31%**
CBO	4.20%	4.55%	**-0.35%**
Composite	4.71%	5.02%	**-0.31%**
Historical 1980 – 2013	5.05%	5.35%	**-0.30%**
Indiana / Top 10 Blue Chip	5.08%	5.78%	**-0.70%**

Q. At the time of the last PGE general rate case, weren't there fears that inputs to long-term growth were eroding in the US?

A. There were articles like the May 9, 2014, edition of the *Oregonian,* "Fear of Economic Blow as Births Drop around World" by Associated Press business writer, Bernard Condon.[20] But the drop in birth rates was not yet built into last year's forecast numbers.

Q. Were global economic inputs like a strong US dollar and quantitative easing stimulus in Japan and Europe also new to this year's forecasts?

A. Yes.

Q. Why does Staff recommend caution in applying the downward impact of current long-term growth forecasts?

A. First, this is a substantial downward revision in expectations – It may be reasonable to move slowly and make sure these projections are durable. Also, PGE's rate case is one of the first to be considered as America curbs long-term expectations, so there is no body of comparable rate case decisions that fully recognize recently released downward long-term growth projections.

Q. How will Staff follow up on this topic in reply testimony?

A. Staff's reply testimony will further evaluate these issues and provide any available updates to long-term growth projections.

Q. Is it appropriate to use estimates of long-term GDP growth rates to estimate future dividends for electric utilities?

A. Yes. Based on information from the EIA, electricity use per 2005 dollar of GPD has been declining over the past 30 years and EIA expects the decline

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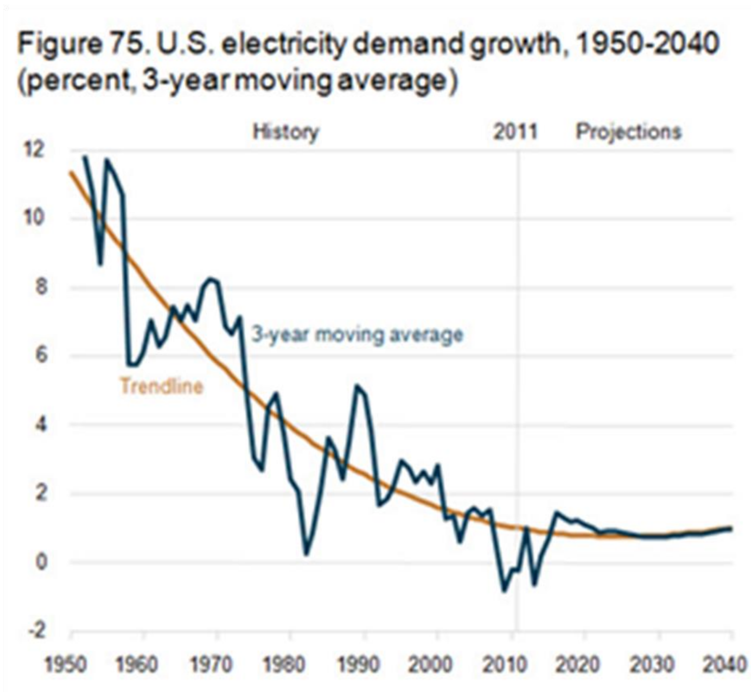
20 See UE 283 Staff/200 Muldoon/14-15.

to continue through 2040.[21] EIA attributes this decline in the growth of electricity usage in part to more efficient appliances and equipment. Total electricity demand grows by just 0.9 percent per year in EIA's primary projection. See Staff Figure 1 – EIA Figure 75 below.

Figure 1

EIA Figure 75



Q. Please Summarize.

A. EIA projects GDP will grow at an average of 2.5 percent from 2011 through 2040. However, EIA projects both delivered residential electricity use and separately delivered electricity use for all sectors combined to grow in the same period at an average of only 0.70 percent, without factoring in electricity

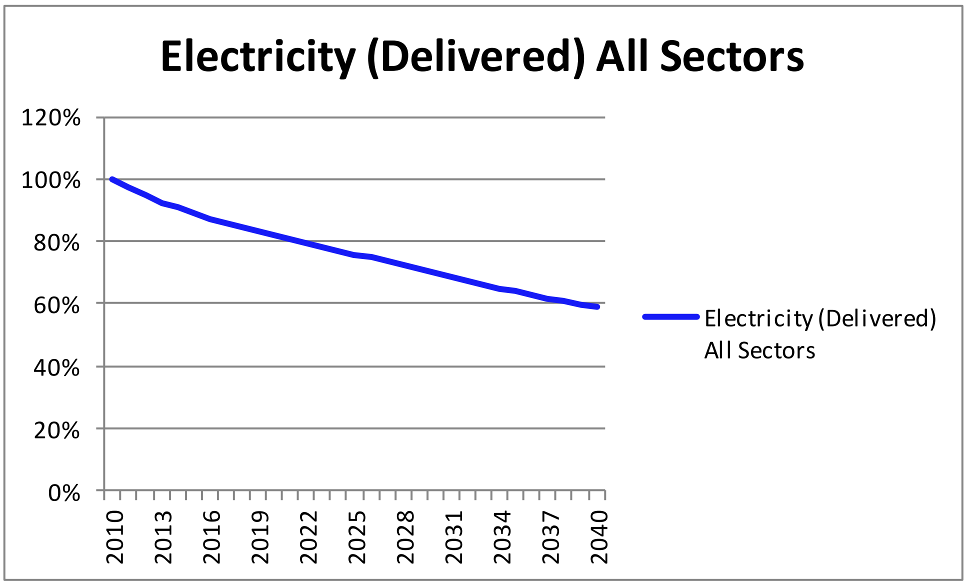
[21] Staff accessed EIA's "Annual Energy Outlook, at http://www.eia.gov/forecasts/aeo/MT_electric.cfm#growth_elec

losses expected to grow 0.4 percent per year on average over this period. See Figure 2 below.

Figure 2

Delivered Electricity as Percent of GDP

Proportional to 2010



Q. Do you use an annual rate of long-term growth less than that estimated for GDP, given the EIA's outlook for the industry, as illustrated In Figures 1 and 2?

A. No. It is possible that my modeling overstates required ROE for this reason.

Q. What are the results of your multistage DCF models?

A. Please see Staff Exhibit 203 for a summary followed by modeling detail.

Q. How do these estimated ROE values compare with national historical electric utilities' ROE values for 2014 General Rate Cases?

A. These estimated ROEs are low compared with regulated US utilities' authorized return on equity capital in 2014 as reported by SNL Financial, LC shown below in Figure 3.

Figure 3

Average ROE in Rate Cases by Quarter & (Quantity of GRCs)

	1st Quarter	10.23	(8)
	2nd Quarter	9.83	(5)
	3rd Quarter	9.87	(12)
	4th Quarter	9.78	(13)
2014	**Full Year**	**9.91**	**(38)**

Q. Would it be reasonable to think that the decision makers setting 2014 ROEs could have anticipated a dramatic drop in Spring-2015 projections of long-term GDP growth?

A. No. Many of the official projections were not released until April of 2015.

Q. Why do you address equity flotation costs when PGE is resolving its equity forward, but not issuing additional new equity now?

A. My 12.5 bps upward adjustment is a durable modifier reflecting aggregate overall long-term cost to float new equity into perpetuity.

Q. What is the Company's requested ROE?

A. PGE asks for an authorized ROE of 9.9 percent.

Q. Have you reviewed Dr. Villadsen's discussion and recommendations related to the Company's requested ROE?

A. I have. Dr. Villadsen's analysis includes constant growth (single stage; Gordon growth) DCF modeling, multi-stage DCF Modeling, risk premium estimates, and CAPM.

Q. What is your assessment of Dr. Villadsen's DCF analysis and results?

A. Dr. Villadsen's modeling of ROE incorporates atypical methods in models that have not been found reliable by the Commission in the past. Staff recommends the Commission use the more realistic expectations applied in Staff's modeling.

Q. The Commission's decision regarding a just and reasonable point value for ROE may hinge on growth rates. Did your analysis include the construction of a synthetic forward curve using UST TIPS break even points?

A. Yes. My forward curve is provided in Staff Exhibit 204, reflecting implied market-based inflationary expectations. Staff's recommendations are consistent with market activity indicating investor expectations of future inflation.

Q. What if one ignored current downward adjustments by a broad spectrum of federal agencies and presumed future US GDP growth would look like the past 30 years – would a ROE based on that assumption fall within Staff's recommended range?

A. Yes, Staff extracted and ran regression on 1980 through 2014 data from US BEA to generate the annual real historical GDP growth rate shown in Table 5.

Staff's recommended range of ROEs includes values presuming GDP growth over the next thirty years would look like that of the past 30 years?

However, the US White House and Congress as well as myriad federal experts expect long term GDP growth to be less than an extrapolation of historical GDP growth. A conservative projection would therefore be lower than GDP growth over the last several decades, not higher.

Q. Does Staff show this analysis in its exhibits?

A. Yes. Staff Exhibit 205 shows Staff's analysis in support of this finding.

Q. And Staff's positions are corroborated by federal sources?

A. Yes. Please see Staff Exhibit 206 for a representative sample.

Q. If utilities' dividends and earnings per share are growing at a faster rate than growth for the whole economy, then utilities would become a bigger part of the economy. Is that happening?

A. No. Electric utilities are not becoming a larger and larger part of the US.[22]

Q. What do you recommend to the Commission regarding Dr. Villadsen's results from her constant growth DCF model?

A. Dr. Villadsen's constant growth DCF model offers little to inform the Commission in this case. For example, the Commission rejected consideration of parties' constant growth DCF models in

[22] See UE 283 Staff/200, Muldoon/17-22.

Docket No. UE 115.[23] I recommend the Commission give little weight to the results of Dr. Villadsen's model.

Q. How do Staff's methods employed in this case differ from those utilized by Staff in PGE's prior general rate cases, UE 283 and UE 262, and by Staff in the recent Northwest Natural Gas Company rate case, UG 221?

A. I examine several sensitivities that have the effect of increasing the upper range of my range of ROE reasonableness. I also have one adjustment for common equity flotation costs that shifts my entire range of reasonable ROEs upward by 12.5 bps. Otherwise my methods and modeling are very similar to those employed by Staff in recent general rate cases, including UE 283.

ALTERNATIVE MODELS EXAMINED

Q. What control modeling does Staff perform to corroborate DCF results?

A. I examine several alternative models that support Staff's DCF modeling. While I do not recommend that any alternate approach should replace the Commission's reliance on three-stage DCF modeling, such alternate models may offer a check on the reasonableness of Staff's recommendation.

SINGLE-STAGE GORDON GROWTH DCF MODELING

Q. Did you first examine the Company's constant Gordon growth DCF model described in PGE/1100, Villadsen/36?

A. Yes. However, I note that Brealey, Myers and Allen, in the tenth edition of their textbook "Principles of Corporate Finance" caution that "the simple

23 See page 27 of Order No. 01-777. See also page 24 of Order No. 01-787 in Docket No. UE 116.

constant-growth DCF formula is an extremely useful rule of thumb, but no more than that."[24]

Q. Does Staff see this model as simply an extremely imprecise vector pointing closer to 10 percent ROE than 5 percent ROE or 15 percent ROE?

A. Yes. As calculated by PGE, this vector would point toward the top end of Staff's three-stage DCF results when considering a point ROE from among a reasonable range of ROEs.

Q. Looking at Exhibit PGE/1101 Villadsen/2, please explain why you are uncomfortable relying overly much on this simple Gordon growth model.

A. If we narrow in on Idaho Power in Panel A on that page, we see a simple Gordon Growth model generated 5.7 percent required return for Idaho Power. Staff is skeptical that Idaho Power would agree that that single data point represents a reasonable value for that utility. Gordon Growth makes the academic assumption that information about returns forever is all contained in just a few values: namely the last dividend and an appropriate very long-term average growth rate.

Q. Why is this not plausible in the real world?

A. Were Gordon Growth even somewhat accurate, success in investing would be assured and there would be less need for the omnipresent investment disclaimer, "Past Performance is No Guarantee of Future Results". Staff

[24] "Principles of Corporate Finance", Brealey, Myers, and Allen, p 83 (10th Edition 2010).

recommends the Commission continue to assign little or no weight to Gordon Growth modeling and to be very skeptical of findings that average such weak extrapolations equally with results from much higher confidence modeling.

Q. What would be a better way to think of single-stage Gordon Growth DCF results than averaging such with other methods equally?

A. Staff's three-stage DCF result of 9.13 percent point ROE is the two-thirds point in a range of 8.27 percent to 9.57 percent. Some investors may interpret the results of a single-stage DCF model as recommending the upper end of Staff's range of reasonable and supportable ROEs for PGE, absent other considerations.

RISK PREMIUM MODELING

Q. Did you examine Dr. Villadsen's risk premium modeling in PGE/1100?

A. Yes, and Staff's reply testimony will address this and other modeling performed in this case by ICNU. However, I found PGE's results are skewed by reliance on the thinly traded and unrepresentative 20-year UST.

Figure 4

Figure 4 above shows that the cost between 10-year and 30-year most commonly issued long-term utility bonds is not linear. Rather costs curve upward proportionally for a 20-year bond as shown by the following basic Bloomberg chart. 20-year bonds comprise so little of OPUC jurisdictional debt as to be almost entirely divorced from any hope to extrapolate historical data for some other group of companies to predict forward looking utility experience.

Q. Are you saying that utilities like PGE tend not to issue 20-year debt other than in private placement or when that maturity is specifically beneficial due to low rates or debt maturity considerations as in the May 2015 PGE issuance?

A. Yes, PGE bonds issued May 2015 will mature in a year with no other maturing debt. But studying 20-year debt offers little insight to PGE's historical experience and likely has no predictive value regarding the Company's required ROE with investors, other than as shown above. The thin market skews spreads upward over underlying UST. As you can see to the right there is not enough investor interest in 20-year debt for UST of this maturity to merit daily reporting in the Wall Street Journal.[25]

Bond Market Overview	
US Treasurys	
8:29 p.m. EDT 05/21/15	
1-Month Bill	0.020
3-Month Bill	0.018
6-Month Bill	0.079
1-Year Note	0.191
2-Year Note	0.581
3-Year Note	0.955
5-Year Note	1.517
7-Year Note	1.916
10-Year Note	2.192
30-Year Bond	2.986

[25] See the WSJ, Bond Markets Overview daily at www.WSJ.com Staff accessed this page on June 2, 2015 at http://www.wsj.com/public/page/news-fixed-income-bonds.html.

Q. Are the UST rates included in your response above a representative snapshot of where fixed income rates are heading?

A. No. John Lonski, Chief Economist of Moody's Capital Markets Research, Inc. in Credit Markets Review and Outlook released March 21, 2015, called the current state of business activity "mediocre".[26] His assessment is that the recent jump by Treasury yields may have overstated any rise by inflation risk, and that there are no "observable facts" behind it. If he is right, UST prices will rise and yields fall once again, absent news recommending otherwise. Rather, the important thing to note is that investors and publications for investors first track 10-year UST, often track 30-year UST and very seldom track or report 20-year debt.

Q. Are risk premium conclusions also impacted by data timing?

A. Yes. Inclusion or exclusion of the crisis years in Figure 5 below demonstrates how spreads and their implications would vary by years studied:

Q. Does Dr. Villadsen also use 20-year UST in CAPM modeling?

A. Yes. This is peculiar enough to note. Dr. Villadsen adds the spread between 20-year and 10-year government bond yields to create a synthetic forward, which shifts expected results upwards by about one percent.

Q. Is this necessary or typical?

A. No. Bloomberg forwards directly provide this information.

[26] Staff accessed Moody's reporting on May 22, 2015 at https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_181342

Q. Is there good reason to believe that PGE's examination of historical fixed income data is not predictive of the future – not even to describe conditions in 2016 at the end of the test year?

A. Yes. The US Federal Reserve (Fed) is considering whether the financial crisis and Great Recession permanently slowed the US economy's growth potential, thereby lowering the point at which the Fed's benchmark interest rate should be considered neutral. April Fed policy minutes released May 20, 2015, defined this "equilibrium rate" as the level of the Fed funds rate, adjusted for inflation, consistent with the economy achieving, over a specified time horizon, maximum employment and price stability.[27]

Q. Are you implying that Fed management of rates might not match an extrapolation of prior fixed income activity?

A. Yes, extrapolating historical data would have difficulty predicting trillion dollar quantitative easing stimulus in the US, EU and Japan. How the Fed defines its target states can impact the timing and nature of Fed actions which may overwhelm historic fixed income against common equities comparison trends.

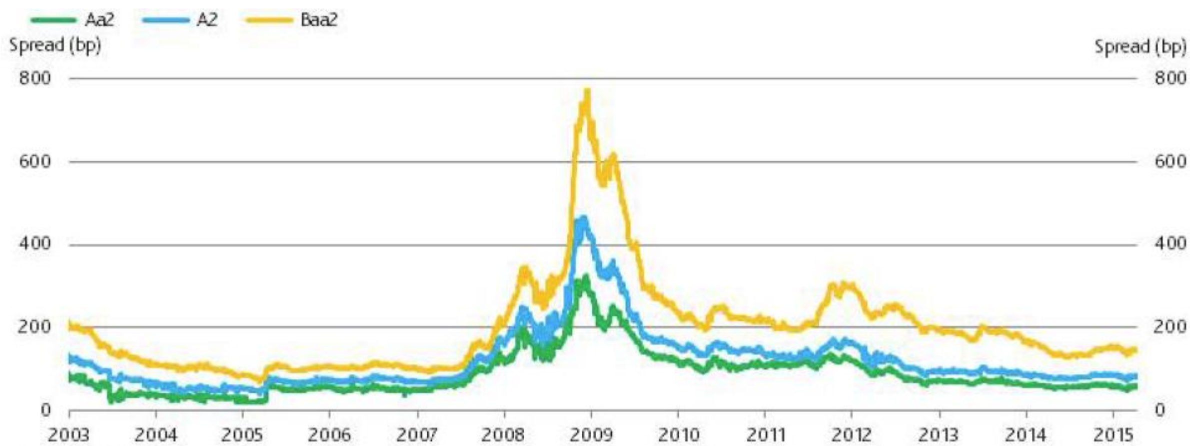
Q. Do credit ratings heavily impact spreads over UST?

A. Yes, consideration of bonds that poorly mirror PGE's first mortgage bond (FMB) ratings could substantially inflate implied spreads over UST. Below in Figure 5, Moody's shows that bringing in lower rated bonds can boost

27 Staff accessed the WSJ article, "A New, Lower Normal for Fed Rates? Fed Officials' Lively Debate" by Pedro Nicolaci da Costa on May 22, 2015, at **www.WSJ.com.**

spreads over UST by one percent. Inclusion of low rated bonds for 2009 can further escalate implied impacts.

Figure 5



Source: Moody's

Q. Please discuss the Ibbotson approach you used.

A. The Research Foundation of CFA Institute, an impartial non-profit organization, published "Rethinking the Equity Risk Premium" in 2011. Herein, Professor Roger Ibbotson of the Yale School of Management and other earlier examiners of how best to approach and calculate equity risk premiums share their current thinking and findings.

"In the 85 years covered by the Ibbotson data, stocks delivered a real return of 6.6% against 2.1% for bonds, supporting a 4.5% equity risk premium."[28] Adding that 4.5 percent to Dr. Villadsen's 4.41 percent long-term UST rate for 2015 to 2016, would suggest that an investor looking just for a quick rough estimate should demand about an 8.9 percent ROE to be satisfied to own a stock of average risk in 2015 to 2016.

[28] "Rethinking the Equity Risk Premium," Research Foundation of CFA Institute p 81 (2011).

REBUTTAL OF PGE'S CAPM MODELING

Q. Did you examine and make adjustments to PGE's CAPM modeling yielding different results than Dr. Villadsen?

A. Yes. The Company generates both a variant of traditional CAPM and ECAPM. As I see no investor or fund management firm using ECAPM, I suggest the Commission afford ECAPM no weight whatsoever. For CAPM, I note that the Company relies on a 6.96 percent market risk premium. This is interesting in that that value could be seen as a long-run complete market return.

The Company also relies on the earlier discussed peculiar synthetic construct of 20 year bond spreads applied to Blue Chip Economic Indicators. Unaware of anyone with money at risk using such a method, I rely directly on average April 2015 Bloomberg forward 10- and 30-year UST yields for January 15, 2016. This removes up to about one percent off of the risk free rate. My 3.09 percent 10-year and 3.83 percent 30-year risk free rates are both examined to generate a range of reasoned returns.

I also calculate expected returns using both Value Line and Yahoo Finance Betas which employ different indices, sampling methods and assumptions about mean reversion. Relying on an Ibbotson market risk premium of 4.50 percent, I see a range of expected return of 5.53 percent to 7.32 percent. These values are markedly lower than the expected returns shown on PGE/1104 Villadsen/2.

Q. What do you conclude regarding the direction CAPM offers?

A. The Company appears to ignore the low end of industry practice using CAPM. PGE also relies on a high market risk premium. PGE uses 20-year debt rather than typical 10- and 30-year teaching and money management methods. PGE also focuses on after tax cost of long-term debt out of context. When Staff's typical finance approach is added to PGE's CAPM work, the result is a lower return on capital midpoint.

Q. What are Staff's intermediate CAPM findings?

A. Staff's modeling alone generates a 7.32 percent return on peer equity at the high end of pre-tax CAPM results considering both 10- and 30-year UST as risk free rates, and considering both Value Line and Yahoo Finance Betas.

Q. Understanding that both Staff and the Commission have placed minimal weight on CAPM modeling results and that Staff only discuses Company results as a check in due diligence on Staff findings, what is the implication of CAPM expected returns on risky assets?

A. William Forsyth Sharpe, Professor of Economics at Stanford and one of winners of the 1990 Nobel Memorial Prize in Economic Sciences for the CAPM suggests that the expected return on a portfolio of stocks, as estimated by CAPM should approximate the peer securities' cost of capital.

In the context of this rate case CAPM can be interpreted as a downward pointing vector suggesting that one can reasonable look at less than the upper end of Staff's three-stage DCF modeling results. Table 5 below shows a typical CAPM model inclusive of common variations.

Table 5 – Typical CAPM Modeling

3.09%	Risk Free Rate as 10 Yr UST as of Jan. 15, 2016					$R_{PGE} = R_f$+Beta*MRP			
3.83%	Risk Free Rate as 30 Yr UST as of Jan. 15, 2016					w 10 Yr Forward UST		w 30 Yr Forward UST	
4.50%	Ibbotson Market Risk Premium					CAPM	CAPM	CAPM	CAPM
		Abbreviated	UE 294	UE 294		w VL	w Yahoo	w VL	w Yahoo
	#	Utility	PGE	Staff	Ticker	Beta	Beta	Beta	Beta
	1	AEP	Yes	Yes	AEP	6.24%	5.34%	6.98%	6.08%
	2	Allete	Yes	No	ALE	6.69%	7.59%	7.43%	8.33%
	3	Alliant	Yes	No	LNT	6.69%	5.66%	7.43%	6.40%
	4	Ameren	Yes	No	AEE	6.47%	5.84%	7.21%	6.58%
	7	CenterPoint	Yes	No	CNP	6.47%	5.93%	7.21%	6.67%
	10	CMS	Yes	No	CMS	6.24%	3.72%	6.98%	4.46%
	11	Consol Ed	Yes	No	ED	5.79%	4.08%	6.53%	4.82%
	12	Dominion	Yes	No	D	6.24%	4.62%	6.98%	5.36%
	13	DTE	Yes	Yes	DTE	6.47%	4.67%	7.21%	5.41%
	15	Edison Int'l	Yes	Yes	EIX	6.47%	5.12%	7.21%	5.86%
	16	El Paso	Yes	No	EE	6.24%	5.93%	6.98%	6.67%
	18	Entergy	Yes	No	ETR	6.24%	4.94%	6.98%	5.68%
	21	Great Plains	Yes	Yes	GXP	6.92%	6.65%	7.66%	7.39%
	23	IDACORP	Yes	Yes	IDA	6.69%	7.19%	7.43%	7.93%
	26	MGE	Yes	No	MGEE	6.24%	6.87%	6.98%	7.61%
	31	OGE	Yes	No	OGE	7.14%	6.15%	7.88%	6.89%
	32	Otter Tail	Yes	Yes	OTTR	7.14%	8.13%	7.88%	8.87%
	34	PG&E	Yes	Yes	PCG	6.02%	4.71%	6.76%	5.45%
	35	PGE	Yes	No	POR	6.69%	6.24%	7.43%	6.98%
	36	Pinnacle	Yes	No	PNW	6.24%	5.75%	6.98%	6.49%
	37	PNM	No	Yes	PNM	6.92%	6.20%	7.66%	6.94%
	39	Public Serv.	Yes	No	PEG	6.47%	5.340%	7.21%	6.08%
	40	SCANA	Yes	No	SCG	6.47%	4.71%	7.21%	5.45%
	41	Sempra	Yes	No	SRE	6.47%	4.71%	7.21%	5.45%
	42	Southern	Yes	No	SO	5.57%	4.08%	6.31%	4.82%
	46	Vectren	Yes	No	VVC	6.69%	6.65%	7.43%	7.39%
	47	Westar	Yes	Yes	WR	6.47%	5.34%	7.21%	6.08%
	49	Xcel	Yes	No	XEL	6.02%	4.22%	6.76%	4.96%
		Peers:	27	9	Peers				
			Avg	Peers	PGE	6.41%	5.53%	7.15%	6.27%
			Avg	Peers	Staff	6.58%	5.77%	7.32%	6.51%
					Range	From:	5.53%	To:	7.32%
						Staff	Midpoint	6.43%	

Q. What is the formula used above?

A. The formula follows in Figure 6.

Figure 6 – CAPM Formula

$$\bar{r}_a = r_f + \beta_a(\bar{r}_m - r_f)$$

Where :

r_f = Risk free rate

β_a = Beta of the security

$\bar{r}_m$ = Expected market return

$(\bar{r}_m - r_f)$ = Equity market premium

Q. PGE's current Rate of Return (ROR) is 7.560. Do lower CAPM results, while holding PGE's Cost of LT Debt unchanged from the last general rate case, suggest that PGE's required ROE could be lower?

A. Yes, CAPM modeling contains more information than Gordon Growth estimations and does suggest that PGE's required ROE should be lower than currently authorized, however Staff recommends that the Commission put little weight on this methodology.

Q. Why does Staff feel it is necessary to rebut PGE's CAPM testimony and to clarify that one normally calculates CAPM using a 10-year UST yield or the 30-year UST as the risk free rate; and logically relies on average Bloomberg forwards and an Ibbotson market premium rather than unique synthetic approximations of what these values might be?

A. Though the Commission does not favor CAPM, Staff conducted its review considering that the Commission could alter its policy going forward.

Q. Does Staff disagree with PGE's use of after tax long-term debt to derive required ROEs from CAPM?

A. Yes. While one can multiply the before-tax rate by one minus the marginal tax rate to calculate after-tax cost of long-term debt, it would be illogical to do so in this instance.

Q. Why is that? Don't investors care about after-tax cost of capital?

A. Investors do care about their returns after taxes. However, PGE, as shown in Table 2 above, asks for consideration of a proposed 5.443 pre-tax cost of long-term debt in considering the Company's required rate of return (ROR).

PGE does not ask for the lower after-tax 3.755 percent cost of long term debt resulting in a lower 6.827 percent ROR. So it would be illogical to use after-tax cost of long-term debt in the same matrix to propose logical values for reasonable ROE.

Q. Please show Table 2 modified to show the range of results from the CAPM model as typically deployed.

A. Table 6 below shows these modeling results which consist of a range of ROEs from 5.635 percent to 9.202 percent with a midpoint ROE of 7.418 percent.

Table 6 – Results from Typical Use of CAPM Model

Avg Tax Rate	2015	2017-2019
Co Peers	32%	32%
Staff Peers	30%	31%

PGE Proposed (UE 294)			(as filed)	
Component	Percent of Total	Cost	Weighted Average	ROR vs. Current
Long Term Debt	50%	5.433%	2.717%	
Preferred Stock	0%		0.000%	
Common Stock	50%	9.900%	4.950%	
	100%		7.667%	7.667%

High End

ROE ex PreTax CAPM			(LT Debt as filed)	
Component	Percent of Total	Cost	Weighted Average	ROR vs. Current
Long Term Debt	50%	5.433%	2.717%	
Common Stock	50%	9.202%	4.601%	
	100%		7.318%	7.318%

Low End

ROE ex PreTax CAPM			(LT Debt as filed)	
Component	Percent of Total	Cost	Weighted Average	ROR vs. Current
Long Term Debt	50%	5.433%	2.717%	
Common Stock	50%	5.635%	2.817%	
	100%		5.534%	5.534%

PreTax Range of CAPM ROE's				
	From	5.635%	to	9.202%
		Midpoint	7.418%	

Q. Is Staff saying that persons managing money at risk gain little new information from a typically calculated CAPM, other than a downward

vector recommending use of the midpoint or lower in Staff's other modeling?

A. Yes. Staff is merely showing how CAPM is usually calculated in comparison with the calculations PGE has prepared for the Commission's consideration. And given the low pointing vector, the Commission may want to consider a lower point ROE than the highest modeling result in Staff's range of reasonable ROEs.

PGE'S COMPARATIVE RISKINESS

Q. Is PGE a regulated utility that enjoys various revenue smoothing and guaranteeing mechanisms and also just had a credit rating increase?

A. Yes. Moody's upgraded PGE's ratings on January 30, 2014, but S&P has not followed with a like upgrade to date.

Q. Noting that PGE is self-building multiple generation plants, is PGE more or less risky than the average electric utility, and riskier or less risky than the average publicly traded US stock?

A. Common sense tells us that PGE is reflective of peer electric utilities of like size and material statistics, absent other factors. PGE is without doubt less risky than the average publicly traded US stock.

As mentioned earlier though, PGE is unique among its peers as the peer group has been compiled by Staff for purposes of determining an appropriate ROE. None of PGE's like-regulated electric peer utilities has filed three consecutive general rate cases in the last five years. PGE has also successfully managed these recent cases to reduce regulatory lag for its capital additions, further reducing its risk compared to its peers.

Q. Along with methods to recognize costs as new generation goes into service, how do PGE's frequent filings impact ratepayer perception regarding PGE's risks and attractiveness of investment opportunity?

A. Prompt cost recovery and regulatory certainty has allowed PGE to depict expansion of its generation capabilities as a solid positive for investors. As an example of this see Exhibit 208.

Q. What do these rough alternative modeling methods, which are regularly used by investors for ballpark calculations, indicate?

A. Investors applying the simple constant-growth DCF formula see a recommendation of the top end of Staff's range of reasonable ROEs. Investors applying Ibbotson equity premium thinking or traditional CAPM modeling see a recommendation for the lower end of Staff's range of reasonable ROEs.

Q. How could investors check the reasonableness of modeling results.

A. Without consideration of below average risk due to multiple-year consecutive rate cases, investors applying the full spectrum of supported growth rates from a composite (relying on historical experience and federal projections) to most optimistic Top 10 Blue Chip from PGE's last general rate case in Staff's three-stage DCF models would see results of 8.27 percent to 9.57 percent. Finding Mid-Cap results best fit PGE's prospects, investors could narrow expectations to Staff's 8.75 percent to 9.57 percent reasonable range of

ROEs with a recommended midpoint of 9.16 percent. Table 7 below summarizes Staff's modeling results.

Table 7
Results of Staff's Modeling
(See Exhibit Staff/203 for more detail)

Range of Reasonable ROEs	8.75%	to	9.57%
(Best fit is Staff screened electric utilities that have similar mid-cap capitalization size like PGE)			
Midpoint of Mid-Cap Modeling Results		9.16%	
(Staff's informed judgement excludes some of the lower range of modeling results depicted above)			

Table 8
Check for Reasonableness of Staff's Point ROE

Check of Reasonableness:			
Last Commission Authorized ROE:		9.68%	
Modeled Change in Long-Term GDP Growth		9.37%	(less 31 bps)
Reduction in risk from frequent rate cases,	9.00%	to	9.37%
and prompt cost recovery for new facilities.			
Staff Point ROE Recommendation:		9.16%	

Q. Referring to Table 8, please explain why a 9.16 percent midpoint is a reasonable point ROE?

A. The Commission's authorized ROE in PGE's last general rate case is a sound starting point for a mental check of reasonableness of Staff recommendations. The first adjustment to the last general rate case results is to reduce the cost of equity for changes in growth expectations. The lowering of growth expectations reduces the cost of equity by 31 basis points yielding an ROE of 9.37 percent. The next adjustment is to reflect the reduction in risk associated with frequent general rate case filing. PGE's very frequent rate cases and tracking mechanisms for prompt cost recovery of new facilities in my reasoned judgement merit a further drop of up to 37 basis points. This provides a range of 9.37 to 9.00 percent. The value of 9.16 percent falls solidly within that check of reasonable ROEs.

Q. What is the impact on investor expectations to the upper cap on reasonable ROEs of 9.57 percent were investors to rely on current April 2015 projections of long term GDP growth and remove consideration of PGE's last rate case Top-Ten Blue Chip optimistic growth?

A. In that case, Staff's upper limit of a range of reasonable ROEs would be 9.26 percent.

EQUITY FORWARD

Q. Has Staff carefully analyzed PGE's equity forward?

A. Yes. Staff has reviewed the confidential cost profile of the Company's equity forward against alternatives that PGE considered.

Q. Has Staff formed any general conclusions regarding equity forwards as a result of this analysis?

A. No. Each equity forward requires careful consideration prior to execution. In PGE's specific context, in this instance, the equity forward 1) assured Company, investors and ratepayers of certainty in the range of generated proceeds; 2) delayed the impact of draw down on funds until cash was needed for utility purposes; 3) added flexibility to offset the Company's temporary inability to issue First Mortgage Bonds (FMB);[29] and 4) was appropriate to the unique market conditions at time of issuance.

[29] Three forced outages put temporary pressure on PGE cash flows and interest coverage ratios.

Q. What current cash flows are associated with the Equity Forward Sale Agreement (EFSA) that PGE entered into on June 11, 2013 for 11,100,000 shares of the Company's Common Stock?

A. On June 10, 2015, PGE physically settled in full the EFSA, with the issuance of the remaining 10,400,000 shares of common stock available under the agreement, in exchange for net proceeds of $271 million.[30]

Q. Staff recommends the Commission continue to find PGE's equity forward prudent in the current instance, but in no way precedent setting?

A. Yes. PGE's positive current equity forward arrangement and execution to date afforded high certainty at controlled cost and risk, particularly when bolstered by Commission flexibility with regard to 2014-2015 debt issuances, within current market conditions. However, future conditions will vary.

<u>ADJUSTMENT OF MODELING RESULTS</u>

Q. What sets PGE apart from the risks of its own proxy group as assembled by Staff?

A. PGE has filed three rate cases in past three years. Given the Company's relatively low growth rate, capacity to file a rate case each year, and less need to plan for long term, PGE has become less risky than its peer utilities. The Maryland commission finds that similar factors reduce risk and regulatory

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[30] PGE filed a Form-8 Current Report with the U.S. Securities and Exchange Commission (SEC) on June 10, 2015, making this detail of the EFSA public information.

lag in the current environment, meriting a lower point ROE from within a reasonable range of ROEs.[31]

In addition, as indicated in PGE's filing, the Company will add a new gas-fired plant, Carty, to its fleet in the May to June 2016 time period. The Commission has allowed trackers to add new generation plant to rate base in other dockets, and may allow similar regulatory treatment for Carty. PGE is therefore not subject to much regulatory lag and is demonstrating better ability to manage risk than the Company's peers.

Q. Does any other party detect a pattern of rate case filings inclusive of the treatment of new generation and transmission facilities creating a reduction in risk for PGE?

A. The Citizen's Utility Board of Oregon (CUB) states in opening power cost testimony that "PGE's rate case is designed in a way as to minimize the risk that the Company might suffer regulatory lag on the fixed cost recovery. At the same time, it creates a lag in recognizing the (*Net Variable Power Costs*) NVPC benefits of the plant. This means that while shareholders will get full recovery of their capital investment, customers will not fully benefit from the offset from reduced NVPC."[32]

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[31] See Public Service Commission of Maryland, Order No. 85374, Case No. 9299, at 78 – February 22, 2013, accessible at: http://webapp.psc.state.md.us/Intranet/Casenum/CaseForm_new.cfm

[32] See UE 294 CUB/100 Jenks-McGovern/2 at lines 10-13.

Q. In Order No. 09-020, the Commission concluded that the adoption of decoupling justified a ROE reduction of 10 bps for PGE. Does Staff recommend a similar outboard reduction in ROE for PGE now?

A. No. Staff recommends the Commission consider a lower than top ROE from within the range of reasonable ROEs in Staff's modeling reflective of the lower risk profile PGE has achieved by effectively managing regulatory lag.

Q. Is Staff opposed to regulatory certainty for PGE?

A. No. Staff merely notes that PGE has successfully managed regulatory risk and conveyed that story well to Moody's.

HAMADA EQUATION

Q. Staff Application of the Hamada Equation to un-lever peer utility capital structures and to re-Lever at PGE'S target capital structure increases required ROE by 7 bps. Why is this adjustment reasonable?

A. Staff usually employs the Hamada Equation as a check on the reasonableness of Staff Modeling. As earlier discussed, Staff's screening criteria already identify peers that have very close capital structure to PGE's. Use of the Hamada adjusted results helps insure that Staff has captured all material risk in its analysis.

Q. Does Staff agree with PGE's Use of the Hamada Equation?

A. No. Staff observes that PGE researched the academic origins of the Hamada Equation. However, PGE appears to pursue historical capital structure inputs in lieu of forward readily accessible Value Line projections Staff's applies the higher of results from VL current and VL projected future Hamada inputs.

There are numerous variants in the use of the Hamada equation. Staff methods are straightforward and consistent with an investor checking their work prior to executing investment decisions.

Q. In addition to 65 standard data requests and 19 multiple-part follow up data requests; did Staff also rely on information from any other party in Staff's analysis?

A. Yes. Staff also noted CUB's shared perception of PGE's effective management of risk and minimization of regulatory lag in cost recovery.[33]

INFORMED STAFF ANALYSIS

Q. Did Staff take into account information from other models?

A. Yes. Staff performed a constant-growth DCF model analysis using the Company's inputs and methods and performed a rough equity risk premium analysis relying on an approach discussed by Professor Roger Ibbotson of the Yale School of Management in *Rethinking the Equity Risk Premium.*[34] Staff also showed how CAPM as typically calculated suggests Staff's three-stage DCF modeling is reasonable and well considered.

Q. Does Staff monitor and analyze current and projected market conditions?

A. Yes. Staff's analysis includes analysis of the current economic climate and its impact on Staff's estimates of long-term growth. Staff also relies heavily on feeds from SNL Financial LC, Bloomberg, Moody's, S&P, WSJ and other

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[33] CUB/100, Jenks-McGovern/3, lines 9-13.

[34] Staff/200, Muldoon/24-25.

sources to make sure that its financial understandings are reflective of investor expectations.

Q. Did Staff develop its recommendations while informed by authorized ROEs in other parts of the country?

A. Yes. Staff examined recently authorized ROEs across the nation.

Q. Did Staff use robust and proven analytical methodologies?

A. Yes. Staff methods are similar to Staff's work over the last decade. The difference in this rate case is that Staff has shown a spotlight on CAPM and will continue to illuminate other methods used by the Company in this rate case. This scrutiny will afford the Commission a chance to see the divergent paths that PGE and Staff used in deploying both methods the Commission has relied heavily on and methods that have proven worthy of less weight in the past.

Q. Briefly recap changes since the last PGE general rate case in estimates of long-term growth in gross domestic product (GDP).

A. From 2008 through PGE's last general rate case, referent economists, government agencies, university business schools, and business leaders expressed at least some expectation on average that American worker populations, productivity and aggregate output would return to pre-recession trends. Over the last year the broad consensus picked up dramatically in long-term GDP projections was that America has challenging fundamental problems in sustaining historic GPD growth.

Q. As the growth rate is pivotal in this case, please describe what long-term growth rates Staff relied on.

A. The lowest estimate of long-term GDP growth, 4.71 percent, is a weighted average of historic GDP and forecasts from three federal sources. Fifty-percent weight is applied to the aggregate estimates of long-term GDP by the EIA, the OMB, and the CBO, with each federal source receiving one-third of the 50 percent weight. The remaining 50 percent is the average annual historical real GDP growth rate, established with a regression analysis, for the period 1980 through 2014, to which Staff applied the TIPs inflation forecast.

Q. What is Staff's second growth rate?

A. Staff's second long-term growth rate of 4.80 percent, is PGE's Blue Chip and OMB rate, which is higher than the Blue Chip average 2021-2025 rate of 4.40%. Staff presumes that PGE's input is drawing on Blue Chip expectations prior to 2020 based on this value.

Q. What is Staff's third growth rate?

A. Staff's third growth rate, 5.08 percent, is the current Indiana / Blue Chip Top 10 growth projection through 2019. This reflects the growth that 9 of 10 referent and informed current Blue Chip survey responders would find higher than they could support. It also matches the modeling input cited by Indiana University's Kelley School of Business. This value may be seen as the highest current expectation of forward GDP rates for financial modeling purposes.

Q. Does Staff's analysis and recommendation ignore the highest one in ten super optimistic forecasters of GPD Growth as of PGE's last general rate case?

A. No. Staff's fourth and highest growth rate, 5.78 percent, is the Indiana Blue Chip Top 10 growth projection from the last PGE general rate case. However, Staff clarifies that this high growth is provided so that the Commission can consider the dramatic change in national expectations for long-term growth in context.

Q. How are the four growth rates used in Staff's analysis?

A. Using the cohort of proxy companies that met Staff's screens, Staff ran each of its two DCF models four times, each time using a different long-term growth rate.

Q. How did Staff evaluate the Company's peer cohort and test for the impact of company size on its modeling results?

A. After performing these initial eight runs, Staff performed sensitivity analysis.

Q. Please describe this process.

A. First, Staff re-ran each model four times, again using the conservative, mid-range, and optimistic long-term growth rates for the terminal growth stage as described above, as well as the Top-10 Blue Chip growth from the last general rate case.

Q. What was the next step?

A. Next, Staff ran each of its models imposing a mid-capitalization (Mid-Cap) size screen between two and ten billion capitalization to refine the cohort to utilities with comparable capitalization to PGE.

Q. How did Staff test the impact of PGE's peer company selection?

A. Finally, Staff ran each of its models using PGE's cohort of 27 proxy companies, again using the four different long-term growth rates for the third stage of growth that are discussed above.

Q. How did Staff adjust for capital structures divergent to PGE's?

A. Staff used the Hamada equation to de-lever or remove debt from the proxy companies and then to re-lever or add debt to match PGE's 50 percent equity target capital structure in this rate case.

Q. What other adjustment does Staff make in this case?

A. Staff makes an upward adjustment of 12.5 basis points to account for the cost of PGE's equity flotation inclusive of a portion of interest carrying cost for an equity forward provision.

Q. Does Staff's range of reasonable ROEs encompass the entirety of these modeling results including the results for each peer group and sensitivity examined?

A. Yes. The lower end of Staff's range of reasonable ROEs is most impacted by Staff's composite growth rate, which is informed by federal forecasts of GDP growth as compared to like projections from the same agencies a year ago.

Q. Is the upper end of Staff's range of reasonable ROEs driven by results from the Company's peer group utilizing the top growth rate?

A. Interestingly no. Staff's Mid-Cap sensitivity generated higher required ROE results than did the Company's peer group. Staff's upper range of reasonable ROEs is from the Mid-Cap sensitivity peer group utilizing the highest growth rate adjusted for divergent capital structure from PGE's.

Q. To clarify, Staff's recommendation includes results from the Company's peer group, but because the Company's peer group did not produce the highest modeling results, Staff's range of reasonable ROEs brackets the results for the Company's peer group?

A. Yes. Were Staff to rely on the Company's peer group and remove Staff's Mid-Cap sensitivity peer set, Staff's upper limit in its range of recommended ROEs would be lower.

UPDATES TO PGE MODELS

Q. Currently Staff has the freshest data in its modeling along with more current long-term projections. Should the Commission see dated inputs as technical deficiencies?

A. No, with each successive round of testimony, the Commission sees updates to inputs refreshing modeling.

Q. What difference does reasonable expectation of appeal make to Staff's testimony on Cost of Capital?

A. Staff has endeavored to provide complete working models and self-contained explanations and background materials. This level of introduction may appear a bit extensive for the third general rate case in three years, but this testimony may also need to inform persons who have not experienced the prior two rate cases.

Q. Does Staff's screening eliminate companies that are not like PGE?

A. Yes. The point of screening is to identify a small group of companies with very similar characteristics to PGE that can act as a close proxy for PGE. By modeling and examining the proxy group, investors may project information not directly observable from PGE. As the peer group grows, information is diluted by information from Companies that no longer resemble PGE closely.

<u>ISSUE 3 – COST OF LT DEBT</u>

Q. Has Staff compiled a summary table illustrating its calculation of PGE's cost of long-term debt?

A. Yes, please see Staff Exhibit 207.

Q. Is this table updated to reflect PGE's May debt issuance?

A. Yes, The 6.80 percent, $67 million, 7-year series maturing Jan. 2016 was earlier replaced by a like maturity pro forma series in 2016. However, the updated table's capture of PGE's issuance of replacement debt this May also removes Staff's earlier projected pro forma series.

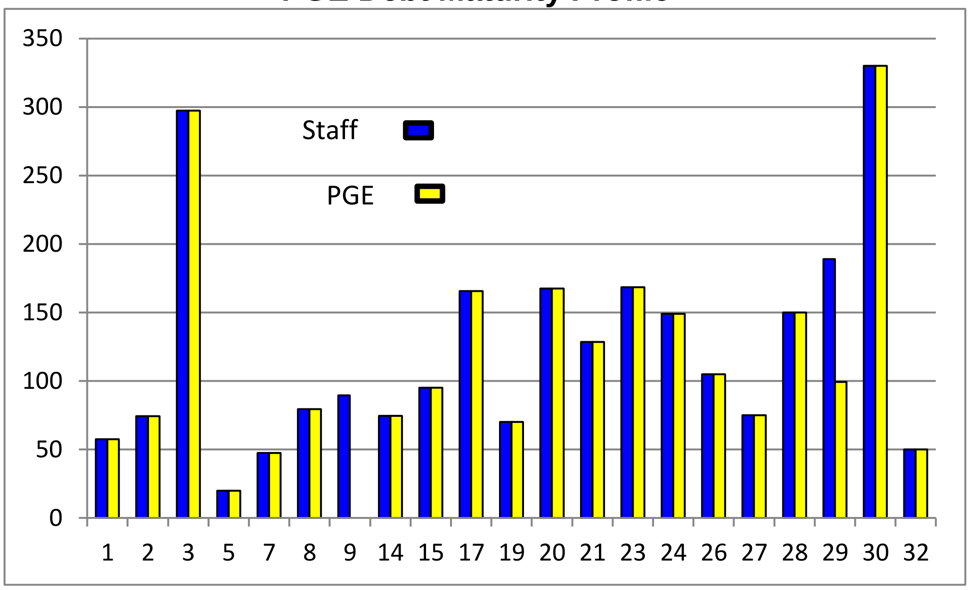
Q. Is this LT Debt table also updated to address PGE's planned revisions to its 2015 LT Debt issuances provided Staff on June 2, 2015?

A. Yes. However Staff believes that the actual mix of long term debt maturities may vary as provided in Confidential Staff Exhibit 207. Staff's table avoids some of the pressure created by debt maturing thirty years from the test year, while creating no challenging pressure ten years from the test year.

Q. How does Staff recommend the Commission address planned 2015 bond issuances and 2016 debt in general?

A. Staff recommends the Commission take a measured approach. PGE faces two challenges in its debt maturity profile as the rate case was filed. The actual May 2015 issuance, in lieu of the 2016 debt issuance planned when the rate case was filled, mitigates some of the 3- and 30-year maturity concentration to that shown below in Figure 7.

Figure 7
PGE Debt Maturity Profile



Q. Does Staff recommend the Commission update the cost of long-term debt to reflect actual 2015 issuances arranged prior to November 2015?

A. Yes, it is reasonable for the Commission to accept actual values provided the Commission by this November. The Commission has long precedent of incorporating best available facts. Further, arrangement by the end of this summer has the potential to capture historically low coupon rates in advance of any interest rate "liftoff" decision by the Fed.

Staff notes that PGE does not project any debt issuances in 2016. Staff does not have a recommendation at this time as to how to handle the case where PGE issues LT Debt in 2016.

Q. Why does Staff recommend this substantial flexibility for PGE?

A. The flexibility recommended will permit PGE to prudently act to best finance necessary utility activity at least cost and controlled risk in the context of this general rate case. While no person can perfectly time markets, PGE is operating in a near-term debt market with short convective patterns on UST yields that later this year may be affected by either press releases or actions by the Fed.

Q. To review, does Staff recommend 5.235 percent cost of LT Debt for PGE, with the expectation that this position may be updated with actual information from 2015 issuances prior to the Commission's decision date on this matter?

A. Yes.

ISSUE 4 – AFUDC

Q. Has Staff reviewed PGE calculations and unique methods for recording the Allowance for Funds Used during Construction (AFUDC)?

A. Yes, Staff also held a workshop with the Company and issued follow up data requests to better understand PGE's processes and to verify that each difference in PGE methodology from default practice was fully authorized.

Q. Does Staff summarize its review of PGE AFUDC in this testimony?

A. No, Staff will lay out its findings in reply testimony in this rate case as Staff analysis is not yet complete.

Q. Does Staff recommend an adjustment to AFUDC?

A. No, but, a concise report on Staff's investigation into this topic will memorialize findings to the benefit of future auditors and investigators.

CONCLUSION

Q. What is Staff's recommendation regarding ROE?

A. Staff recommends that the Commission consider a range of reasonable ROEs from 8.75 percent to 9.57 percent, and a point ROE of 9.16 percent. This is the midpoint in Staff's range of reasonable ROEs. Please note that Staff's recommendation still reflects and is inclusive of the Top-10 Blue Chip most optimistic growth rate from PGE's last general rate case.

Q. How do you conclude your testimony?

A. It is not remarkable that PGE looks like a well-run utility to Value Line with average risk on dimensions that matter to investors. A solid utility that plans ahead and proactively controls risks meets the needs of risk-averse ratepayers. This stability and management strength also makes PGE common stock attractive to institutional and conservative investors who rely on stable growing dividends to meet their obligations in turn.

Q. Why do you recommend the Commission consider a lower point ROE than the uppermost ROE resultant from Staff's modeling?

A: There are two key reasons: First, this is PGE's third consecutive annual general rate case, complete with methods for rapid cost recovery of new generation. PGE's management has controlled risk and regulatory lag well. This success is making PGE less risky than its peers, as compiled by Staff, none of whom have filed rate cases with this frequency in the last five years.

Q. What is the second reason?

A: Since PGE's last general rate case, there has developed a broad consensus that US GDP will not return to pre-recession trends. Rather than directly shifting required ROE downward by 31 basis points, Staff recommends the Commission continue to consider the cliff edge and take this information under advisement in selecting a point ROE.

Q. Do you have any criticism of PGE in this rate case?

A: No. Staff merely points out that PGE needs consistent messaging in all arenas that the Company is skillfully managing risk, controlling cost, and expediting cost recovery within a supportive regulatory environment. Success in that repeated communication offers the potential of a rating upgrade by S&P. Achieving that S&P rating upgrade unlocks PGE's still higher Moody's rating to lower financing and credit costs.

Q. Do you expect a lower authorized ROE to hurt PGE's credit profile?

A: No. Moody's Investors Service on March 1, 2015 examined this subject in its publication, "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles."

Q. What are the key drivers underlying Moody's findings?

A: Moody's review, provided as Exhibit Staff/210, noted three key factors:

1. More Timely Cost Recovery Helps Offset Falling ROEs;
2. Utilities' Cash Flow is Somewhat Insulated from Lower ROEs; and
3. Utilities' Actual Financial Performance Remains Stable.

Q. Does that conclude your opening testimony?

A. Yes.

CASE: UE 294
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualification Statement

June 15, 2015

WITNESS QUALIFICATION STATEMENT

NAME:	Matthew J. Muldoon
EMPLOYER:	PUBLIC UTIILTY COMMISSION OF OREGON
TITLE:	Senior Economist Utility Program Energy – Rates Finance and Audit Division
ADDRESS:	3930 Fairview Industrial Dr. SE Salem, OR 97302-1166.
EDUCATION:	In 1981, I received a Bachelors of Arts Degree in Political Science from the University of Chicago. In 2007, I received a Masters of Business Administration from Portland State University with a certificate in Finance.
EXPERIENCE:	From April of 2008 to the present, I have been employed by the OPUC. My current responsibilities include financial and rate analysis with an emphasis on cost of capital. From 2002 to 2008 I was Executive Director of the Acceleration Transportation Rate Bureau, Inc. where I developed new rate structures for surface transportation and created metrics to insure program success within regulated processes. I was the Vice President of Operations for Willamette Traffic Bureau, Inc. from 1993 to 2002. There I managed tariff rate compilation and analysis. I also developed new information systems and did sensitivity analysis for rate modeling.
OTHER:	I have prepared, and defended formal testimony in contested hearings before the OPUC, ICC, STB, WUTC and ODOT. I have also prepared OPUC Staff testimony in BPA rate cases.

CASE: UE 294
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Staff Peer Screening

Exhibits in Support
of Opening Testimony

June 15, 2015

Electric Utilities Screened by Staff and PGE

Small Cap	Under 2 Billion
Mid Cap	2 Billion to 10 Billion
Large Cap	Over 10 Billion

Staff Peer Screening

1	Continuity Screen
2	Sensitivity Mid Cap
3	PGE Peer Group

#	Abbreviated Utility	UE 294 PGE	UE 283 PGE	UE 262 PGE	UE 215 PGE	UE 294 Staff	UE 283 Staff	UE 262 Staff	UE 215 Staff	VL Corporate Name Electric Utility
1	AEP	**Yes**	No	No	Yes	**Yes**	Yes	Yes	Yes	American Electric Power Company, Inc.
2	Allete	**Yes**	Yes	Yes	Yes	**No**	Yes	No	Yes	Allete, Inc.
3	Alliant	**Yes**	Yes	Yes	Yes	**No**	No	No	No	Alliant Energy Corporation
4	Ameren	**Yes**	No	No	Yes	**No**	No	No	No	Ameren Corporation
5	Avista	No	Yes	Yes	Yes	**No**	No	Yes	No	Avista Corporation
6	Black Hills	No	Yes	Yes	No	**No**	No	No	No	Black Hills Corporation
7	CenterPoint	**Yes**	No	No	No	No	No	No	No	CenterPoint Energy, Inc.
8	**CH Energy**	No	No	No	No	**No**	No	No	No	**CH Energy Group, Inc.**
9	Cleco	No	Yes	Yes	Yes	No	Yes	Yes	Yes	Cleco Corporation
10	CMS	**Yes**	Yes	Yes	Yes	No	No	No	No	CMS Energy Corporation
11	Consol Ed	**Yes**	No	No	No	No	No	No	No	Consolidated Edison, Inc.
12	Dominion	**Yes**	No	No	No	No	No	No	No	Dominion Resources, Inc.
13	DTE	**Yes**	No	No	Yes	**Yes**	Yes	Yes	No	DTE Energy Company
14	Duke	No	No	No	Yes	**No**	No	No	No	Duke Energy Corporation
15	Edison Int'l	**Yes**	No	No	Yes	**Yes**	Yes	Yes	No	Edison International
16	El Paso	**Yes**	No	No	No	**No**	No	No	No	El Paso Electric Company
17	Empire	No	No	Yes	Yes	**No**	No	No	Yes	Empire District Electric Company
18	Entergy	**Yes**	No	No	Yes	**No**	No	No	No	Entergy Corporation
19	**Exelon**	No	No	No	No	**No**	No	No	No	Exelon Corporation
20	First Energy	No	No	No	Yes	**No**	No	No	No	FirstEnergy Corporation (Formerly in part: Allegheny)
21	Great Plains	**Yes**	Yes	No	Yes	**Yes**	No	No	No	Great Plains Energy Incorporated
22	**Hawaiian**	No	Yes	Yes	Yes	**No**	No	No	No	Hawaiian Electric Industries, Inc.
23	IDACORP	**Yes**	Yes	Yes	Yes	**Yes**	Yes	Yes	Yes	IDACORP, Inc.
24	**Integrys**	No	No	No	No	**No**	No	No	No	Integrys Energy Group, Inc.
25	ITC	No	No	No	No	No	No	No	No	ITC Holdings Corp.
26	MGE	**Yes**	Yes	Yes	Yes	No	No	No	No	MGE Energy, Inc.
27	NE Utilities	No	No	No	No	No	No	No	No	Northeast Utilities
28	NextEra	No	No	No	Yes	**No**	No	No	No	NextEra Energy, Inc. (Formerly: FPL Group, Inc.)
29	NorthWestern	No	Yes	Yes	Yes	**No**	No	Yes	No	NorthWestern Corporation
30	**NV Energy**	No	No	Yes	No	**No**	No	No	No	**NV Energy Inc.**
31	OGE	**Yes**	Yes	Yes	Yes	No	No	No	No	OGE Energy Corporation
32	Otter Tail	**Yes**	No	No	No	**Yes**	No	No	No	Otter Tail Corporation
33	**Pepco**	No	No	No	No	**No**	No	No	No	Pepco Holdings, Inc.
34	PG&E	**Yes**	No	No	Yes	**Yes**	Yes	Yes	Yes	PG&E Corporation
35	**PGE**	**Yes**	Yes	Yes	Yes	**No**	No	No	No	**Portland General Electric Company**
36	Pinnacle	**Yes**	Yes	Yes	Yes	No	No	No	Yes	Pinnacle West Capital Corporation
37	PNM	No	Yes	No	No	**Yes**	No	No	No	PNM Resources, Inc.
38	PPL	No	No	No	No	No	No	No	No	PPL Corporation
39	Public Serv.	**Yes**	No	No	No	No	No	No	No	Public Serv. Enterprise Group, Inc.
40	SCANA	**Yes**	Yes	Yes	No	No	No	No	No	SCANA Corporation
41	Sempra	**Yes**	No	No	No	No	No	No	No	Sempra Energy
42	Southern	**Yes**	No	No	Yes	No	No	No	No	Southern Company, The
43	**TECO**	No	Yes	Yes	Yes	**No**	No	Yes	Yes	**TECO Energy, Inc.**
44	**UIL**	No	No	No	No	**No**	No	No	Yes	**UIL Holdings Corporation**
45	**UNS**	No	Yes	Yes	Yes	**No**	No	No	No	**UNS Energy Corporation (Formerly: UniSource)**
46	Vectren	**Yes**	No	No	No	No	No	No	No	Vectren Corporation
47	Westar	**Yes**	Yes	Yes	Yes	**Yes**	Yes	Yes	Yes	Westar Energy, Inc.
48	**Wisconsin**	No	Yes	Yes	Yes	**No**	No	No	Yes	**Wisconsin Energy Corporation**
49	Xcel	**Yes**	No	No	Yes	No	No	No	Yes	Xcel Energy, Inc.
	No. of Peers:	**27**	20	20	31	**9**	8	10	13	
						3	**Small Cap Sensitivity**			

Staff Peer Screen

#	Abbreviated Utility	UE 294 PGE	UE 294 Staff	VL 2/10/2015 Beta	Yahoo Fin. 2/10/2015 Beta	Yahoo Fin. 2/10/2015 Mkt Cap $ Billions	Covered by Value Line 2/10/2015 (VL)	VL 2/25/2015 No Div Declines 5 years	S&P 3/3/2015 Local LT Debt Rating	Credit Rating BB+ to BBB+	EEI 3/3/2015 80% Regulated Assets	VL 3/3/2015 LT Debt 45% - 55% of Capital	VL Forecast Div. Growth 5 Yr Rate > 0%	No M&A Detected Activity in Last 5 Years
1	AEP	Yes	Yes	0.70	0.50	29.00	Yes	Pass	BBB	Pass	80% +	53%	Yes	Nov 1999 Merged w CSR, May 2011 Float
2	Allete	Yes	No	0.80	1.00	2.37	Yes	Pass	BBB+	Pass	80% +	46%	Yes	Feb, 2015 1st Water Purchase $168M = U.S. Water Services Inc Δstrategy
3	Alliant	Yes	No	0.80	0.57	7.33	Yes	Pass	A-	Fail	80% +	48%	Yes	Selling MN Electric & N Gas Dist to Coop Group Announced Apr. 17, 2014 SNL
4	Ameren	Yes	No	0.75	0.61	10.52	Yes	Pass	BBB+	Pass	80% +	46%	Yes	Mar 2013,$900M Sale of Merch. Gen. (5 Power Plants) to Dynergy / SNL
5	Avista	No	No	0.80	0.74	2.20	Yes	Pass	BBB	Pass	80% +	49%	Yes	M&A - Purchase of AERC Completed 2014 after Sale of Ecova Completed
6	Black Hills	No	No	0.90	1.10	2.26	Yes	Pass	BBB	Pass	80% +	52%	Yes	Black Hills to buy MGTC transmission & distribution utility assets / SNL 2014
7	CenterPoint	Yes	No	0.75	0.63	9.74	Yes	Pass	A-	Fail	50% to 80%	52%	Yes	CenterPoint Unlikely to Acquire Cleco / SNL 2014
8	CH Energy	No	No	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Feb 2012 Bought by Fortis
9	Cleco	No	No	0.80	0.54	3.26	Yes	Pass	BBB+	Pass	80% +	43%	Yes	CenterPoint Unlikely to Acquire Cleco / SNL 2014
10	CMS	Yes	No	0.70	0.14	9.97	Yes	Pass	BBB	Pass	80% +	68%	Yes	No M&A
11	Consol Ed	Yes	No	0.60	0.22	19.62	Yes	Pass	A-	Fail	80% +	48%	Yes	No M&A
12	Dominion	Yes	No	0.70	0.34	44.76	Yes	Pass	A-	Fail	50% to 80%	63%	Yes	No M&A
13	DTE	Yes	Yes	0.75	0.35	15.35	Yes	Pass	BBB+	Pass	80% +	51%	Yes	Mar 2001 Merged w MCN
14	Duke	No	No	0.60	0.27	59.54	Yes	Pass	BBB+	Pass	80% +	51%	Yes	Jan 2011 Bought Progress Energy
15	Edison Int'l	Yes	Yes	0.75	0.45	21.50	Yes	Pass	BBB-	Pass	80% +	45%	Yes	Aug 2000 Bought Citizens Power
16	El Paso	Yes	No	0.70	0.63	1.57	Yes ***	Fail	BBB	Pass	80% +	56%	Yes	No M&A
17	Empire	No	No	0.70	0.63	1.14	Yes	Fail	BBB	Pass	80% +	51%	Yes	No M&A
18	Entergy	Yes	No	0.70	0.41	14.67	Yes	Pass	BBB	Pass	80% +	58%	Yes	Mar 2013 Merger w FPL Group, Dec 2011 Sold Trans. to ITC
19	Exelon	No	No	0.70	0.46	30.08	Yes	Fail	BBB	Pass	50% to 80%	44%	Yes	Exelon Purchase of Pepco Announced May 7, 2014 $6.83 Billion SNL
20	First Energy	No	No	0.70	0.33	16.25	Yes	Fail	BBB-	Pass	50% to 80%	56%	No	No M&A
21	Great Plains	Yes	Yes	0.85	0.79	4.32	Yes	Pass	BBB+	Pass	80% +	49%	Yes	No M&A
22	Hawaiian	No	No	0.80	0.22	3.47	Yes	Pass	BBB-	Pass	Under 50%	47%	Yes	Proposed Sale of HECO to Next Era for $4.3B / SNL Feb. 2, 2015
23	IDACORP	Yes	Yes	0.80	0.91	3.22	Yes	Pass	BBB	Pass	80% +	48%	Yes	No M&A
24	Integrys	No	No	0.80	0.59	6.27	Yes	Pass	A-	Fail	80% +	47%	No	Wisconsin Energy to Buy Integrys Energy Group
25	ITC	No	No	0.65	0.35	6.19	Yes	Pass	A-	Fail	N/A	68%	Yes	Dec 2011 Bought Entergy Transmission – 8K Apr 2013 Voted Y
26	MGE	Yes	No	0.70	0.84	1.55	Yes	Pass	AA-	Fail	50% to 80%	39%	Yes	No M&A
27	NE Utilities	No	No	0.75	0.58	17.32	Yes	Pass	A-	Fail	80% +	46%	Yes	Oct 2010 Merged w Nstar
28	NextEra	No	No	0.70	0.36	47.66	Yes	Pass	A-	Fail	50% to 80%	53%	Yes	Proposed Sale of HECO to Next Era for $4.3B / SNL Feb. 2, 2015
29	NorthWestern	No	No	0.70	0.64	2.18	Yes	Pass	BBB	Pass	80% +	50%	Yes	2014 Acquisition $900M to buy 633 MW Hydro Capacity in MT
30	NV Energy	No	No	N/A	N/A	N/A	N/A	N/A	BBB+	Pass	N/A	N/A	N/A	Purchased in 2013 by MEH – Now BKE
31	OGE	Yes	No	0.90	0.68	6.73	Yes	Pass	A-	Fail	80% +	44%	Yes	No M&A
32	Otter Tail	Yes	Yes	0.90	1.12	1.15	Yes	Pass	BBB	Pass	80% +	49%	Yes	No M&A
33	Pepco	No	No	0.70	0.19	6.89	Yes	Pass	BBB+	Pass	80% +	48%	No	Exelon Purchase of Pepco Announced May 7, 2014 $6.83 Billion SNL
34	PG&E	Yes	Yes	0.65	0.36	26.99	Yes	Pass	BBB	Pass	80% +	48%	Yes	July 1997 Purchased Valero Energy
35	PGE	Yes	No	0.80	0.70	2.95	Yes	Pass	BBB	Pass	80% +	45%	Yes	No M&A
36	Pinnacle	Yes	No	0.70	0.59	7.47	Yes	Pass	A-	Fail	80% +	46%	Yes	Pinnacle W's AZ Pub Service (APS) Buying $182 M 4-Corners Coal Gen
37	PNM	No	Yes	0.85	0.69	2.35	Yes	Pass	BBB	Pass	80% +	52%	Yes	PNM 2001 Merger w Western Resources
38	PPL	No	No	0.60	0.54	23.50	Yes	Pass	BBB	Pass	50% to 80%	57%	Yes	No M&A
39	Public Serv.	Yes	No	0.75	0.50	20.72	Yes	Pass	BBB+	Pass	50% to 80%	42%	Yes	No M&A
40	SCANA	Yes	No	0.75	0.36	8.73	Yes	Pass	BBB+	Pass	50% to 80%	56%	Yes	SCANA Feb 2015 closed the $150 million sale of SCANA Communications to Spirit
41	Sempra	Yes	No	0.75	0.36	27.17	Yes	Pass	BBB+	Pass	50% to 80%	51%	Yes	No M&A
42	Southern	Yes	No	0.55	0.22	44.25	Yes	Pass	A	Fail	80% +	56%	Yes	No M&A
43	TECO	No	No	0.85	0.68	4.88	Yes	Pass	BBB+	Pass	80% +	58%	Yes	TECO to Buy NM Gas for $950 M per SNL, May 14, 2014
44	UIL	No	No	0.80	0.61	2.47	Yes	Pass	BBB	Pass	80% +	58%	No	UIL Called Off Deal to Acquire Philadelphia Gas Works for $1.86B on Dec 4 / WSJ
45	UNS	No	No	0.75	N/A	N/A	Yes	Pass	N/A	Fail	80% +	63%	Yes	Fortis to Acquire UNS for $4.3B in Q1 2015
46	Vectren	Yes	No	0.80	0.79	3.83	Yes	Pass	A-	Fail	50% to 80%	52%	Yes	No M&A
47	Westar	Yes	Yes	0.75	0.50	5.37	Yes	Pass	BBB+	Pass	80% +	51%	Yes	No M&A
48	Wisconsin	No	No	0.65	0.30	12.13	Yes	Pass	A-	Fail	80% +	50%	Yes	Buying Integrys for $4.6B in Common Stock and $1.5B Cash
49	Xcel	Yes	No	0.65	0.25	18.33	Yes	Pass	A-	Fail	80% +	54%	Yes	No M&A

CASE: UE 294
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Staff Three Stage DCF Modeling

Exhibits in Support
of Opening Testimony

June 15, 2015

Required ROE
Results from Three Stage DCF Modeling

Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity (Hamada Adjusted)								
X	**Composite Growth**	**4.71%**	**PGE BlueChip & OMB**	**4.80%**	**Top-10 LT Blue Chip Growth**	**5.08%**	**UE 283 Top-10 Growth**	**5.78%**
Staff Peers	8.21%	Implied Average ROE	8.27%	Implied Average ROE	8.48%	Implied Average ROE	8.99%	Implied Average ROE
Sensitivity 1 Mid-Cap	8.62%		8.68%		8.88%		9.39%	
Sensitivity 2 Co. Peers	8.15%		8.21%		8.42%		8.93%	

Model Y: 3 Stage DCF - Dividend Growth with Terminal Value as Sales based upon EPS Growth and Terminal Stock Sale (Hamada Adjusted)								
Y	**Composite Growth**	**4.71%**	**PGE BlueChip & OMB**	**4.80%**	**Top-10 LT Blue Chip Growth**	**5.08%**	**UE 283 Top-10 Growth**	**5.78%**
Staff Peers	8.17%	Implied Average ROE	8.22%	Implied Average ROE	8.39%	Implied Average ROE	8.80%	Implied Average ROE
Sensitivity 1 Mid-Cap	8.81%		8.87%		**9.03%**		9.44%	
Sensitivity 2 Co. Peers	8.31%		8.36%		8.52%		8.93%	

Values Shown Above Are NOT Adjusted for Equity Flotation Costs

Staff Interpretation of ROE Modeling Results

Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by :					**12.5**	**bps**
Range of Reasonable ROEs	**8.75%**	**to**	**9.57%**			
(Best fit is Staff screened electric utilities that have similar mid-cap capitalization size like PGE)						
Midpoint of Mid-Cap Modeling Results		**9.16%**				
(Staff's informed judgement excludes some of the lower range of modeling results depicted above)						
Check of Reasonableness:						
Last Commission Authorized ROE:		**9.68%**				
Modeled Change in Long-Term GDP Growth		**9.37%**	(less 31 bps)			
Reduction in risk from frequent rate cases,	**9.00%**	**to**	**9.37%**			
and prompt cost recovery for new facilities.						
Staff Point ROE Recommendation:		**9.16%**				
* Staff Blue Chip Data is sourced from Table 1 Blue Chip Economic Forecast, Feb. 2015						

Note: Please see next pages for illustrations of Three Stage DCF calculations.
Staff work papers contain the spreadsheets for these models in larger print as well as sensitivities examined.

Staff Model X – Dividend Growth with Terminal Value as Perpetuity

5.08%	Annual Growth Rate - Stage 3	Dividend Growth with Terminal Value as Perpetuity

E.O.Y. Cash Flows **Staff** UE 294 **Model** **X**

Row	# (1)	Abbreviated Utility (2)	PGE (3)	Staff (4)	IRR (5)	Terminal Value as % of NPV_{DIV} (6)	NPV @ IRR (7)	Recent Price* (8)	2014 (9)	2015 (10)	2016 (11)	2017 (12)	2018 (13)	2019 (14)	2020 (15)	2021 (16)	2022 (17)	2023 (18)	2024 (19)
									Initial Stage						Transition Stage				
1	1	AEP	Yes	Yes	8.5%	58.8%	0.00	(58.52)	2.03	2.15	2.26	2.38	2.50	2.62	2.76	2.90	3.05	3.21	3.37
2	2	Allete	Yes	No	8.3%	60.6%	0.00	(54.54)	1.96	2.04	2.12	2.21	2.30	2.39	2.49	2.59	2.69	2.80	2.91
3	3	Alliant	Yes	No	9.0%	54.8%	0.00	(64.30)	2.04	2.20	2.38	2.58	2.80	3.02	3.27	3.53	3.81	4.12	4.44
4	4	Ameren	Yes	No	8.1%	62.6%	0.00	(42.94)	1.61	1.65	1.70	1.75	1.80	1.85	1.90	1.94	1.99	2.04	2.09
5	7	CenterPoint	Yes	No	10.6%	39.1%	0.00	(21.54)	0.95	1.03	1.11	1.20	1.30	1.40	1.52	1.65	1.79	1.94	2.10
6	10	CMS	Yes	No	8.2%	63.3%	0.00	(35.33)	1.08	1.14	1.21	1.28	1.35	1.42	1.51	1.60	1.69	1.79	1.89
7	11	Consol. Ed.	Yes	No	8.1%	61.7%	0.00	(64.28)	2.52	2.58	2.64	2.69	2.75	2.81	2.87	2.94	3.01	3.07	3.14
8	12	Dominion	Yes	No	8.1%	64.5%	0.00	(72.85)	2.40	2.50	2.60	2.70	2.80	2.90	3.04	3.18	3.32	3.47	3.63
9	13	DTE	Yes	Yes	8.3%	62.1%	0.00	(83.39)	2.69	2.83	2.98	3.14	3.30	3.46	3.66	3.86	4.07	4.29	4.52
10	15	Edison Int'l	Yes	Yes	8.6%	62.5%	(0.00)	(64.73)	1.42	1.71	1.87	2.05	2.25	2.45	2.71	3.01	3.32	3.67	4.04
11	16	El Paso	Yes	No	8.0%	67.1%	0.00	(37.97)	1.11	1.17	1.23	1.29	1.35	1.41	1.49	1.57	1.66	1.75	1.84
12	18	Entergy	Yes	No	8.6%	56.3%	(0.00)	(80.57)	3.32	3.32	3.47	3.63	3.80	3.97	4.08	4.20	4.32	4.44	4.56
13	21	Great Plains	Yes	Yes	8.8%	56.4%	0.00	(27.38)	0.94	1.00	1.06	1.13	1.20	1.27	1.35	1.44	1.53	1.62	1.72
14	23	IDACORP	Yes	Yes	8.1%	66.6%	0.00	(63.62)	1.76	1.90	2.00	2.10	2.20	2.30	2.47	2.65	2.84	3.04	3.25
15	26	MGE	Yes	No	N/A	N/A	N/A	(43.54)	1.11	1.15	1.20	1.25	1.30	1.35	1.41	1.46	1.52	1.59	1.65
16	31	OGE	Yes	No	9.3%	53.6%	0.00	(33.12)	0.93	1.05	1.16	1.27	1.40	1.53	1.69	1.87	2.07	2.28	2.51
17	32	Otter Tail	Yes	Yes	7.9%	64.6%	0.00	(31.80)	1.21	1.23	1.25	1.28	1.30	1.32	1.35	1.37	1.39	1.42	1.44
18	34	PG&E	Yes	Yes	7.9%	66.3%	0.00	(54.87)	1.82	1.82	1.91	2.00	2.10	2.20	2.26	2.33	2.40	2.47	2.55
19	35	PGE	Yes	No	8.1%	65.0%	0.00	(37.46)	1.11	1.17	1.24	1.32	1.40	1.48	1.56	1.64	1.73	1.82	1.91
20	36	Pinnacle	Yes	No	8.5%	58.9%	0.00	(65.45)	2.30	2.44	2.55	2.67	2.80	2.93	3.07	3.23	3.39	3.56	3.73
21	37	PNM	No	Yes	9.3%	54.5%	0.00	(28.84)	0.74	0.80	0.90	1.02	1.15	1.28	1.44	1.61	1.80	2.01	2.23
22	39	Public Serv.	Yes	No	7.6%	69.2%	0.00	(41.52)	1.48	1.52	1.53	1.54	1.55	1.56	1.58	1.61	1.63	1.65	1.68
23	40	SCANA	Yes	No	8.1%	63.6%	0.00	(58.09)	2.08	2.16	2.22	2.28	2.35	2.42	2.49	2.57	2.65	2.73	2.82
24	41	Sempra	Yes	No	7.5%	75.8%	0.00	(109.37)	2.61	2.76	2.90	3.05	3.20	3.35	3.54	3.74	3.94	4.16	4.38
25	42	Southern	Yes	No	8.9%	52.6%	0.00	(46.84)	2.08	2.15	2.22	2.29	2.36	2.43	2.51	2.60	2.69	2.77	2.87
26	46	Vectren	Yes	No	8.1%	64.5%	0.00	(45.16)	1.46	1.54	1.61	1.68	1.75	1.82	1.90	1.98	2.07	2.15	2.24
27	47	Westar	Yes	Yes	8.1%	63.0%	0.00	(39.49)	1.39	1.44	1.49	1.54	1.60	1.66	1.71	1.78	1.84	1.90	1.97
28	49	Xcel	Yes	No	8.4%	60.7%	0.00	(35.63)	1.18	1.26	1.32	1.38	1.45	1.52	1.60	1.69	1.78	1.88	1.98
		TOTALS	27	9	Mean														
				3	8.4%	56.6%	0.0%	Staff											
					8.7%	59.2%	0.0%	Staff (Mid Cap Sensitivity)											
					8.4%	61.3%	0.0%	Staff (Co Peer Sensitivity)											

#	Abbreviated Utility	2025 (20)	2026 (21)	2027 (22)	2028 (23)	2029 (24)	2030 (25)	2031 (26)	2032 (27)	2033 (28)	2034 (29)	2035 (30)	2036 (31)	2037 (32)	2038 (33)	2039 (34)	2040 (35)	2041 (36)	2042 (37)	2043 (38)	2043 Terminal Value (39)	2044 Div (40)	2044 Perpetuity (41)	#	Row
		Final Stage																							
1	AEP	3.54	3.72	3.91	4.11	4.32	4.54	4.77	5.01	5.27	5.54	5.82	6.11	6.42	6.75	7.09	7.45	7.83	8.23	8.65	272.81	9.09	263.72	1	1
2	Allete	3.06	3.21	3.37	3.55	3.73	3.91	4.11	4.32	4.54	4.77	5.02	5.27	5.54	5.82	6.12	6.43	6.75	7.10	7.46	249.69	7.83	241.85	2	2
3	Alliant	4.66	4.90	5.15	5.41	5.68	5.97	6.27	6.59	6.93	7.28	7.65	8.04	8.45	8.88	9.33	9.80	10.30	10.82	11.37	314.53	11.95	302.58	3	3
4	Ameren	2.19	2.30	2.42	2.54	2.67	2.81	2.95	3.10	3.26	3.43	3.60	3.78	3.97	4.18	4.39	4.61	4.85	5.09	5.35	192.25	5.62	186.62	4	4
7	CenterPoint	2.21	2.32	2.44	2.57	2.70	2.83	2.98	3.13	3.29	3.45	3.63	3.81	4.01	4.21	4.42	4.65	4.89	5.13	5.39	108.59	5.67	102.92	7	5
10	CMS	1.99	2.09	2.20	2.31	2.43	2.55	2.68	2.81	2.96	3.11	3.26	3.43	3.61	3.79	3.98	4.18	4.40	4.62	4.85	165.98	5.10	160.88	10	6
11	Consol. Ed.	3.30	3.47	3.65	3.83	4.03	4.23	4.45	4.67	4.91	5.16	5.42	5.70	5.99	6.29	6.61	6.94	7.30	7.67	8.06	286.23	8.47	277.77	11	7
12	Dominion	3.81	4.00	4.21	4.42	4.65	4.88	5.13	5.39	5.66	5.95	6.25	6.57	6.91	7.26	7.63	8.01	8.42	8.85	9.30	335.10	9.77	325.33	12	8
13	DTE	4.75	4.99	5.25	5.51	5.79	6.09	6.40	6.72	7.06	7.42	7.80	8.19	8.61	9.05	9.51	9.99	10.50	11.03	11.59	389.60	12.18	377.42	13	9
15	Edison Int'l	4.24	4.46	4.68	4.92	5.17	5.43	5.71	6.00	6.31	6.63	6.96	7.32	7.69	8.08	8.49	8.92	9.37	9.85	10.35	323.28	10.88	312.40	15	10
16	El Paso	1.94	2.03	2.14	2.25	2.36	2.48	2.61	2.74	2.88	3.02	3.18	3.34	3.51	3.69	3.87	4.07	4.28	4.50	4.72	176.88	4.96	171.91	16	11
18	Entergy	4.79	5.04	5.29	5.56	5.84	6.14	6.45	6.78	7.12	7.49	7.87	8.27	8.69	9.13	9.59	10.08	10.59	11.13	11.69	364.01	12.29	351.72	18	12
21	Great Plains	1.81	1.90	1.99	2.10	2.20	2.31	2.43	2.55	2.68	2.82	2.96	3.11	3.27	3.44	3.61	3.80	3.99	4.19	4.41	129.96	4.63	125.33	21	13
23	IDACORP	3.41	3.58	3.77	3.96	4.16	4.37	4.59	4.83	5.07	5.33	5.60	5.88	6.18	6.50	6.83	7.17	7.54	7.92	8.32	301.30	8.75	292.56	23	14
26	MGE	1.73	1.82	1.91	2.01	2.11	2.22	2.33	2.45	2.57	2.71	2.84	2.99	3.14	3.30	3.47	3.64	3.83	4.02	4.23	#VALUE!	4.44	#VALUE!	26	15
31	OGE	2.64	2.77	2.91	3.06	3.22	3.38	3.55	3.73	3.92	4.12	4.33	4.55	4.78	5.02	5.28	5.55	5.83	6.12	6.43	167.92	6.76	161.16	31	16
32	Otter Tail	1.51	1.59	1.67	1.76	1.85	1.94	2.04	2.14	2.25	2.36	2.48	2.61	2.74	2.88	3.03	3.18	3.34	3.51	3.69	140.75	3.88	136.87	32	17
34	PG&E	2.68	2.81	2.96	3.11	3.26	3.43	3.60	3.79	3.98	4.18	4.39	4.62	4.85	5.10	5.36	5.63	5.92	6.22	6.53	249.16	6.86	242.29	34	18
35	PGE	2.01	2.11	2.22	2.33	2.45	2.58	2.71	2.84	2.99	3.14	3.30	3.47	3.64	3.83	4.02	4.23	4.44	4.67	4.91	175.04	5.16	169.88	35	19
36	Pinnacle	3.92	4.12	4.33	4.55	4.78	5.02	5.28	5.55	5.83	6.12	6.43	6.76	7.10	7.47	7.84	8.24	8.66	9.10	9.56	303.95	10.05	293.90	36	20
37	PNM	2.35	2.47	2.59	2.72	2.86	3.01	3.16	3.32	3.49	3.67	3.85	4.05	4.25	4.47	4.70	4.94	5.19	5.45	5.73	149.14	6.02	143.12	37	21
39	Public Serv.	1.76	1.85	1.95	2.04	2.15	2.26	2.37	2.49	2.62	2.75	2.89	3.04	3.19	3.35	3.53	3.70	3.89	4.09	4.30	183.08	4.52	178.56	39	22
40	SCANA	2.96	3.11	3.27	3.44	3.61	3.79	3.99	4.19	4.40	4.63	4.86	5.11	5.37	5.64	5.93	6.23	6.54	6.88	7.23	262.22	7.59	254.63	40	23
41	Sempra	4.61	4.84	5.09	5.34	5.62	5.90	6.20	6.52	6.85	7.19	7.56	7.94	8.35	8.77	9.22	9.69	10.18	10.69	11.24	508.92	11.81	497.11	41	24
42	Southern	3.01	3.16	3.33	3.49	3.67	3.86	4.05	4.26	4.48	4.70	4.94	5.19	5.46	5.74	6.03	6.33	6.65	6.99	7.35	211.62	7.72	203.90	42	25
46	Vectren	2.36	2.48	2.60	2.73	2.87	3.02	3.17	3.33	3.50	3.68	3.87	4.06	4.27	4.49	4.72	4.95	5.21	5.47	5.75	207.53	6.04	201.49	46	26
47	Westar	2.07	2.18	2.29	2.40	2.53	2.65	2.79	2.93	3.08	3.24	3.40	3.57	3.75	3.95	4.15	4.36	4.58	4.81	5.05	179.55	5.31	174.24	47	27
49	Xcel	2.08	2.19	2.30	2.42	2.54	2.67	2.81	2.95	3.10	3.26	3.42	3.60	3.78	3.97	4.17	4.38	4.61	4.84	5.09	166.44	5.35	161.09	49	28

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B.O.Y. Cash Flows Staff UE 294 Model X

	1	2	3	4	5	6	7	8
	#	Abbreviated Utility	PGE	Staff	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*
1	1	AEP	Yes	Yes	8.7%	56.4%	(0.00)	(58.52)
2	2	Allete	Yes	No	8.5%	58.5%	0.00	(54.54)
3	3	Alliant	Yes	No	9.3%	51.6%	0.00	(64.30)
4	4	Ameren	Yes	No	8.2%	60.9%	0.00	(42.94)
5	7	CenterPoint	Yes	No	10.9%	36.0%	0.00	(21.54)
6	10	CMS	Yes	No	8.4%	60.8%	0.00	(35.33)
7	11	Consol. Ed.	Yes	No	8.3%	60.2%	0.00	(64.28)
8	12	Dominion	Yes	No	8.2%	62.4%	0.00	(72.85)
9	13	DTE	Yes	Yes	8.5%	59.6%	0.00	(83.39)
10	15	Edison Int'l	Yes	Yes	8.8%	58.8%	0.00	(64.73)
11	16	El Paso	Yes	No	8.1%	64.8%	0.00	(37.97)
12	18	Entergy	Yes	No	8.7%	54.5%	0.00	(80.57)
13	21	Great Plains	Yes	Yes	9.0%	53.7%	0.00	(27.38)
14	23	IDACORP	Yes	Yes	8.2%	64.0%	0.00	(63.62)
15	26	MGE	Yes	No	7.5%	74.6%	0.00	(43.54)
16	31	OGE	Yes	No	9.5%	49.9%	0.00	(33.12)
17	32	Otter Tail	Yes	Yes	8.0%	63.1%	0.00	(31.80)
18	34	PG&E	Yes	Yes	8.0%	64.4%	0.00	(54.87)
19	35	PGE	Yes	No	8.3%	62.5%	0.00	(37.46)
20	36	Pinnacle	Yes	No	8.7%	56.6%	0.00	(65.45)
21	37	PNM	No	Yes	9.6%	50.6%	0.00	(28.84)
22	39	Public Serv.	Yes	No	7.7%	68.0%	0.00	(41.52)
23	40	SCANA	Yes	No	8.2%	61.8%	0.00	(58.09)
24	41	Sempra	Yes	No	7.6%	73.6%	0.00	(109.37)
25	42	Southern	Yes	No	9.0%	50.7%	0.00	(46.84)
26	46	Vectren	Yes	No	8.2%	62.3%	0.00	(45.16)
27	47	Westar	Yes	Yes	8.3%	61.1%	0.00	(39.49)
28	49	Xcel	Yes	No	8.6%	58.3%	-	(35.63)
		TOTALS	27	9	Mean			
				3	8.6%	54.5%	0.0%	Staff
					8.9%	56.1%	0.0%	Staff (Mid Cap Sensitivity)
					8.5%	59.6%	0.0%	Staff (Co Peer Sensitivity)

#	9	10	11	12	13	14	15	16	17	18	19
	Initial Stage						Transition Stage				
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
1	2.15	2.26	2.38	2.50	2.62	2.76	2.90	3.05	3.21	3.37	3.54
2	2.04	2.12	2.21	2.30	2.39	2.49	2.59	2.69	2.80	2.91	3.06
3	2.20	2.38	2.58	2.80	3.02	3.27	3.53	3.81	4.12	4.44	4.66
4	1.65	1.70	1.75	1.80	1.85	1.90	1.94	1.99	2.04	2.09	2.19
7	1.03	1.11	1.20	1.30	1.40	1.52	1.65	1.79	1.94	2.10	2.21
10	1.14	1.21	1.28	1.35	1.42	1.51	1.60	1.69	1.79	1.89	1.99
11	2.58	2.64	2.69	2.75	2.81	2.87	2.94	3.01	3.07	3.14	3.30
12	2.50	2.60	2.70	2.80	2.90	3.04	3.18	3.32	3.47	3.63	3.81
13	2.83	2.98	3.14	3.30	3.46	3.66	3.86	4.07	4.29	4.52	4.75
15	1.71	1.87	2.05	2.25	2.45	2.71	3.01	3.32	3.67	4.04	4.24
16	1.17	1.23	1.29	1.35	1.41	1.49	1.57	1.66	1.75	1.84	1.94
18	3.32	3.47	3.63	3.80	3.97	4.08	4.20	4.32	4.44	4.56	4.79
21	1.00	1.06	1.13	1.20	1.27	1.35	1.44	1.53	1.62	1.72	1.81
23	1.90	2.00	2.10	2.20	2.30	2.47	2.65	2.84	3.04	3.25	3.41
26	1.15	1.20	1.25	1.30	1.35	1.41	1.46	1.52	1.59	1.65	1.73
31	1.05	1.16	1.27	1.40	1.53	1.69	1.87	2.07	2.28	2.51	2.64
32	1.23	1.25	1.28	1.30	1.32	1.35	1.37	1.39	1.42	1.44	1.51
34	1.82	1.91	2.00	2.10	2.20	2.26	2.33	2.40	2.47	2.55	2.68
35	1.17	1.24	1.32	1.40	1.48	1.56	1.64	1.73	1.82	1.91	2.01
36	2.44	2.55	2.67	2.80	2.93	3.07	3.23	3.39	3.56	3.73	3.92
37	0.80	0.90	1.02	1.15	1.28	1.44	1.61	1.80	2.01	2.23	2.35
39	1.52	1.53	1.54	1.55	1.56	1.58	1.61	1.63	1.65	1.68	1.76
40	2.16	2.22	2.28	2.35	2.42	2.49	2.57	2.65	2.73	2.82	2.96
41	2.76	2.90	3.05	3.20	3.35	3.54	3.74	3.94	4.16	4.38	4.61
42	2.15	2.22	2.29	2.36	2.43	2.51	2.60	2.69	2.77	2.87	3.01
46	1.54	1.61	1.68	1.75	1.82	1.90	1.98	2.07	2.15	2.24	2.36
47	1.44	1.49	1.54	1.60	1.66	1.71	1.78	1.84	1.90	1.97	2.07
49	1.26	1.32	1.38	1.45	1.52	1.60	1.69	1.78	1.88	1.98	2.08

#	20	21	22	23	24	25	26	27	28	29
	Final Stage									
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
1	3.72	3.91	4.11	4.32	4.54	4.77	5.01	5.27	5.54	5.82
2	3.21	3.37	3.55	3.73	3.91	4.11	4.32	4.54	4.77	5.02
3	4.90	5.15	5.41	5.68	5.97	6.27	6.59	6.93	7.28	7.65
4	2.30	2.42	2.54	2.67	2.81	2.95	3.10	3.26	3.43	3.60
7	2.32	2.44	2.57	2.70	2.83	2.98	3.13	3.29	3.45	3.63
10	2.09	2.20	2.31	2.43	2.55	2.68	2.81	2.96	3.11	3.26
11	3.47	3.65	3.83	4.03	4.23	4.45	4.67	4.91	5.16	5.42
12	4.00	4.21	4.42	4.65	4.88	5.13	5.39	5.66	5.95	6.25
13	4.99	5.25	5.51	5.79	6.09	6.40	6.72	7.06	7.42	7.80
15	4.46	4.68	4.92	5.17	5.43	5.71	6.00	6.31	6.63	6.96
16	2.03	2.14	2.25	2.36	2.48	2.61	2.74	2.88	3.02	3.18
18	5.04	5.29	5.56	5.84	6.14	6.45	6.78	7.12	7.49	7.87
21	1.90	1.99	2.10	2.20	2.31	2.43	2.55	2.68	2.82	2.96
23	3.58	3.77	3.96	4.16	4.37	4.59	4.83	5.07	5.33	5.60
26	1.82	1.91	2.01	2.11	2.22	2.33	2.45	2.57	2.71	2.84
31	2.77	2.91	3.06	3.22	3.38	3.55	3.73	3.92	4.12	4.33
32	1.59	1.67	1.76	1.85	1.94	2.04	2.14	2.25	2.36	2.48
34	2.81	2.96	3.11	3.26	3.43	3.60	3.79	3.98	4.18	4.39
35	2.11	2.22	2.33	2.45	2.58	2.71	2.84	2.99	3.14	3.30
36	4.12	4.33	4.55	4.78	5.02	5.28	5.55	5.83	6.12	6.43
37	2.47	2.59	2.72	2.86	3.01	3.16	3.32	3.49	3.67	3.85
39	1.85	1.95	2.04	2.15	2.26	2.37	2.49	2.62	2.75	2.89
40	3.11	3.27	3.44	3.61	3.79	3.99	4.19	4.40	4.63	4.86
41	4.84	5.09	5.34	5.62	5.90	6.20	6.52	6.85	7.19	7.56
42	3.16	3.33	3.49	3.67	3.86	4.05	4.26	4.48	4.70	4.94
46	2.48	2.60	2.73	2.87	3.02	3.17	3.33	3.50	3.68	3.87
47	2.18	2.29	2.40	2.53	2.65	2.79	2.93	3.08	3.24	3.40
49	2.19	2.30	2.42	2.54	2.67	2.81	2.95	3.10	3.26	3.42

#	30	31	32	33	34	35	36	37	38	39	40	41	#	
	2035	2036	2037	2038	2039	2040	2041	2042	2043	2042 Terminal Value	2044 Div	2044 Perpetuity	#	
1	6.11	6.42	6.75	7.09	7.45	7.83	8.23	8.65	9.09	272.94	9.55	263.39	1	1
2	5.27	5.54	5.82	6.12	6.43	6.75	7.10	7.46	7.83	250.41	8.23	242.18	2	2
3	8.04	8.45	8.88	9.33	9.80	10.30	10.82	11.37	11.95	313.03	12.56	300.47	3	3
4	3.78	3.97	4.18	4.39	4.61	4.85	5.09	5.35	5.62	193.36	5.91	187.45	4	4
7	3.81	4.01	4.21	4.42	4.65	4.89	5.13	5.39	5.67	107.95	5.96	101.99	7	5
10	3.43	3.61	3.79	3.98	4.18	4.40	4.62	4.85	5.10	165.89	5.36	160.53	10	6
11	5.70	5.99	6.29	6.61	6.94	7.30	7.67	8.06	8.47	288.23	8.90	279.33	11	7
12	6.57	6.91	7.26	7.63	8.01	8.42	8.85	9.30	9.77	335.91	10.27	325.65	12	8
13	8.19	8.61	9.05	9.51	9.99	10.50	11.03	11.59	12.18	389.71	12.80	376.91	13	9
15	7.32	7.69	8.08	8.49	8.92	9.37	9.85	10.35	10.88	320.49	11.43	309.06	15	10
16	3.34	3.51	3.69	3.87	4.07	4.28	4.50	4.72	4.96	176.93	5.22	171.71	16	11
18	8.27	8.69	9.13	9.59	10.08	10.59	11.13	11.69	12.29	365.89	12.91	352.98	18	12
21	3.11	3.27	3.44	3.61	3.80	3.99	4.19	4.41	4.63	129.75	4.87	124.89	21	13
23	5.88	6.18	6.50	6.83	7.17	7.54	7.92	8.32	8.75	300.90	9.19	291.71	23	14
26	2.99	3.14	3.30	3.47	3.64	3.83	4.02	4.23	4.44	200.04	4.67	195.37	26	15
31	4.55	4.78	5.02	5.28	5.55	5.83	6.12	6.43	6.76	166.46	7.10	159.36	31	16
32	2.61	2.74	2.88	3.03	3.18	3.34	3.51	3.69	3.88	141.84	4.08	137.76	32	17
34	4.62	4.85	5.10	5.36	5.63	5.92	6.22	6.53	6.86	250.09	7.21	242.88	34	18
35	3.47	3.64	3.83	4.02	4.23	4.44	4.67	4.91	5.16	174.94	5.42	169.52	35	19
36	6.76	7.10	7.47	7.84	8.24	8.66	9.10	9.56	10.05	304.24	10.56	293.68	36	20
37	4.05	4.25	4.47	4.70	4.94	5.19	5.45	5.73	6.02	147.67	6.32	141.35	37	21
39	3.04	3.19	3.35	3.53	3.70	3.89	4.09	4.30	4.52	184.57	4.75	179.82	39	22
40	5.11	5.37	5.64	5.93	6.23	6.54	6.88	7.23	7.59	263.47	7.98	255.49	40	23
41	7.94	8.35	8.77	9.22	9.69	10.18	10.69	11.24	11.81	508.92	12.41	496.51	41	24
42	5.19	5.46	5.74	6.03	6.33	6.65	6.99	7.35	7.72	212.81	8.11	204.69	42	25
46	4.06	4.27	4.49	4.72	4.95	5.21	5.47	5.75	6.04	207.91	6.35	201.56	46	26
47	3.57	3.75	3.95	4.15	4.36	4.58	4.81	5.05	5.31	180.22	5.58	174.64	47	27
49	3.60	3.78	3.97	4.17	4.38	4.61	4.84	5.09	5.35	166.48	5.62	160.86	49	28

Average B.O.Y. & E.O.Y. Cash Flows Model X

	1	2	3	4	5	6	7	8	9	
						Terminal Value as	Average 2014 - 2019 Dividend Growth Rates			
	#	Abbreviated Utility	PGE	Staff	Average IRR	% of NPV_{DIV}	EOY			
1	1	AEP	Yes	Yes	8.6%	57.6%	5.1%	5.1%	5.1%	
2	2	Allete	Yes	No	8.4%	59.6%	4.0%	4.0%	4.0%	
3	3	Alliant	Yes	No	9.1%	53.2%	8.2%	8.2%	8.2%	
4	4	Ameren	Yes	No	8.2%	61.8%	2.9%	2.8%	2.9%	
5	7	CenterPoint	Yes	No	10.8%	37.6%	7.9%	8.1%	8.0%	
6	10	CMS	Yes	No	8.3%	62.0%	5.7%	5.8%	5.7%	
7	11	Consol. Ed.	Yes	No	8.2%	60.9%	2.1%	2.2%	2.2%	
8	12	Dominion	Yes	No	8.2%	63.4%	3.8%	4.0%	3.9%	
9	13	DTE	Yes	Yes	8.4%	60.9%	5.2%	5.3%	5.2%	
10	15	Edison Int'l	Yes	Yes	8.7%	60.6%	9.4%	9.7%	9.5%	
11	16	El Paso	Yes	No	8.0%	65.9%	4.8%	5.0%	4.9%	
12	18	Entergy	Yes	No	8.7%	55.4%	4.6%	4.1%	4.3%	
13	21	Great Plains	Yes	Yes	8.9%	55.1%	6.2%	6.2%	6.2%	
14	23	IDACORP	Yes	Yes	8.1%	65.3%	4.9%	5.5%	5.2%	
15	26	MGE	Yes	No	7.5%	74.6%	4.1%	4.1%	4.1%	
16	31	OGE	Yes	No	9.4%	51.7%	9.8%	10.0%	9.9%	
17	32	Otter Tail	Yes	Yes	8.0%	63.8%	1.9%	1.8%	1.8%	
18	34	PG&E	Yes	Yes	8.0%	65.3%	4.8%	4.4%	4.6%	
19	35	PGE	Yes	No	8.2%	63.8%	6.0%	5.8%	5.9%	
20	36	Pinnacle	Yes	No	8.6%	57.8%	4.6%	4.7%	4.7%	
21	37	PNM	No	Yes	9.4%	52.6%	12.5%	12.4%	12.4%	
22	39	Public Serv.	Yes	No	7.7%	68.6%	0.7%	0.9%	0.8%	
23	40	SCANA	Yes	No	8.1%	62.7%	2.8%	2.9%	2.9%	
24	41	Sempra	Yes	No	7.5%	74.7%	5.0%	5.1%	5.1%	
25	42	Southern	Yes	No	9.0%	51.6%	3.1%	3.2%	3.2%	
26	46	Vectren	Yes	No	8.2%	63.4%	4.3%	4.3%	4.3%	
27	47	Westar	Yes	Yes	8.2%	62.1%	3.5%	3.6%	3.5%	
28	49	Xcel	Yes	No	8.5%	59.5%	4.7%	4.9%	4.8%	
		TOTALS	27	9	MEAN					
				3	8.48%	55.6%	5.9%	6.0%	6.0%	Staff
					8.81%	57.6%	7.9%	8.0%	7.9%	Staff (Mid Cap Sensitivity)
					8.42%	60.7%	4.8%	4.9%	4.9%	Staff (Co Peer Sensitivity)

Staff Model Y – EPS Growth to Determine a Sale Terminal Value

5.08% Annual Growth Rate - Stage 3

EPS Growth to Determine a Sale Terminal Value **EPS Growth**

E.O.Y. Cash Flows **Staff Model Y**

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42		
						Terminal Value as			2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2043					
		Abbreviated				% of	NPV @	Recent	Initial Stage						Transition Stage					Final Stage																			Terminal	2044	2044			
	#	Utility	PGE	Staff	IRR	NPV_{DIV}	IRR	Price*																															Value	Div	Sale	2043	#	
1	1	AEP	Yes	Yes	8.4%	57.3%	0.00	(58.52)	2.03	2.15	2.26	2.38	2.50	2.62	2.76	2.90	3.05	3.21	3.37	3.54	3.72	3.91	4.11	4.32	4.54	4.77	5.01	5.27	5.54	5.82	6.11	6.42	6.75	7.09	7.45	7.83	8.23	8.65	260.65	9.09	251.56		1	1
				e					3.45	3.50	3.66	3.83	4.00	4.17	4.37	4.58	4.79	5.01	5.24	5.50	5.78	6.08	6.39	6.71	7.05	7.41	7.79	8.18	8.60	9.04	9.49	9.98	10.48	11.02	11.58	12.16	12.78	13.43		14.11		14.83		
2	2	Allete	Yes	No	8.8%	67.6%	0.00	(54.54)	1.96	2.04	2.12	2.21	2.30	2.39	2.49	2.59	2.69	2.80	2.91	3.06	3.21	3.37	3.55	3.73	3.91	4.11	4.32	4.54	4.77	5.02	5.27	5.54	5.82	6.12	6.43	6.75	7.10	7.46	306.95	7.83	299.12		2	2
				e					2.85	3.20	3.37	3.56	3.75	3.94	4.23	4.52	4.84	5.17	5.52	5.80	6.10	6.41	6.73	7.07	7.43	7.81	8.21	8.62	9.06	9.52	10.01	10.51	11.05	11.61	12.20	12.82	13.47	14.15		14.87		15.63		
3	3	Alliant	Yes	No	8.9%	52.9%	0.00	(64.30)	2.04	2.20	2.38	2.58	2.80	3.02	3.27	3.53	3.81	4.12	4.44	4.66	4.90	5.15	5.41	5.68	5.97	6.27	6.59	6.93	7.28	7.65	8.04	8.45	8.88	9.33	9.80	10.30	10.82	11.37	296.70	11.95	284.75		3	3
				e					3.45	3.60	3.76	3.93	4.10	4.27	4.48	4.70	4.92	5.16	5.40	5.67	5.96	6.26	6.58	6.91	7.27	7.63	8.02	8.43	8.86	9.31	9.78	10.28	10.80	11.35	11.92	12.53	13.17	13.84		14.54		15.28		
4	4	Ameren	Yes	No	8.4%	67.2%	0.00	(42.94)	1.61	1.65	1.70	1.75	1.80	1.85	1.90	1.94	1.99	2.04	2.09	2.19	2.30	2.42	2.54	2.67	2.81	2.95	3.10	3.26	3.43	3.60	3.78	3.97	4.18	4.39	4.61	4.85	5.09	5.35	220.91	5.62	215.29		4	4
				e					2.35	2.55	2.69	2.84	3.00	3.16	3.34	3.53	3.73	3.94	4.16	4.37	4.60	4.83	5.07	5.33	5.60	5.89	6.19	6.50	6.83	7.18	7.54	7.93	8.33	8.75	9.20	9.66	10.16	10.67		11.21		11.78		
5	7	CenterPoint	Yes	No	10.8%	43.8%	0.00	(21.54)	0.95	1.03	1.11	1.20	1.30	1.40	1.52	1.65	1.79	1.94	2.10	2.21	2.32	2.44	2.57	2.70	2.83	2.98	3.13	3.29	3.45	3.63	3.81	4.01	4.21	4.42	4.65	4.89	5.13	5.39	127.68	5.67	122.01		7	5
				e					1.30	1.30	1.44	1.58	1.75	1.92	2.04	2.17	2.31	2.45	2.60	2.73	2.87	3.02	3.17	3.33	3.50	3.68	3.87	4.06	4.27	4.49	4.71	4.95	5.21	5.47	5.75	6.04	6.35	6.67		7.01		7.36		
6	10	CMS	Yes	No	8.6%	68.4%	0.00	(35.33)	1.08	1.14	1.21	1.28	1.35	1.42	1.51	1.60	1.69	1.79	1.89	1.99	2.09	2.20	2.31	2.43	2.55	2.68	2.81	2.96	3.11	3.26	3.43	3.61	3.79	3.98	4.18	4.40	4.62	4.85	192.95	5.10	187.85		10	6
				e					1.75	1.85	1.97	2.11	2.25	2.39	2.55	2.72	2.90	3.09	3.29	3.45	3.63	3.81	4.01	4.21	4.43	4.65	4.89	5.13	5.40	5.67	5.96	6.26	6.58	6.91	7.26	7.63	8.02	8.43		8.86		9.31		
7	11	Consol. Ed.	Yes	No	7.7%	54.9%	0.00	(64.28)	2.52	2.58	2.64	2.69	2.75	2.81	2.87	2.94	3.01	3.07	3.14	3.30	3.47	3.65	3.83	4.03	4.23	4.45	4.67	4.91	5.16	5.42	5.70	5.99	6.29	6.61	6.94	7.30	7.67	8.06	230.72	8.47	222.26		11	7
				e					3.90	3.95	4.05	4.15	4.25	4.35	4.43	4.51	4.60	4.68	4.76	5.01	5.26	5.53	5.81	6.10	6.41	6.74	7.08	7.44	7.82	8.22	8.63	9.07	9.53	10.02	10.53	11.06	11.62	12.21		12.83		13.48		
8	12	Dominion	Yes	No	8.1%	64.5%	0.00	(72.85)	2.40	2.50	2.60	2.70	2.80	2.90	3.04	3.18	3.32	3.47	3.63	3.81	4.00	4.21	4.42	4.65	4.88	5.13	5.39	5.66	5.95	6.25	6.57	6.91	7.26	7.63	8.01	8.42	8.85	9.30	335.87	9.77	326.10		12	8
				e					3.40	3.65	3.76	3.88	4.00	4.12	4.35	4.59	4.84	5.10	5.38	5.65	5.94	6.24	6.55	6.89	7.24	7.61	7.99	8.40	8.82	9.27	9.74	10.24	10.76	11.31	11.88	12.48	13.12	13.78		14.48		15.22		
9	13	DTE	Yes	Yes	8.3%	62.4%	0.00	(83.39)	2.69	2.83	2.98	3.14	3.30	3.46	3.66	3.86	4.07	4.29	4.52	4.75	4.99	5.25	5.51	5.79	6.09	6.40	6.72	7.06	7.42	7.80	8.19	8.61	9.05	9.51	9.99	10.50	11.03	11.59	393.66	12.18	381.48		13	9
				e					4.45	4.55	4.77	5.01	5.25	5.49	5.80	6.13	6.47	6.82	7.19	7.56	7.94	8.34	8.77	9.21	9.68	10.17	10.69	11.23	11.80	12.40	13.03	13.70	14.39	15.12	15.89	16.70	17.55	18.44		19.37		20.36		
10	15	Edison Int'l	Yes	Yes	8.1%	53.9%	0.00	(64.73)	1.42	1.71	1.87	2.05	2.25	2.45	2.71	3.01	3.32	3.67	4.04	4.24	4.46	4.68	4.92	5.17	5.43	5.71	6.00	6.31	6.63	6.96	7.32	7.69	8.08	8.49	8.92	9.37	9.85	10.35	250.34	10.88	239.47		15	10
				e					4.00	3.75	3.98	4.23	4.50	4.77	4.85	4.95	5.04	5.13	5.23	5.49	5.77	6.07	6.37	6.70	7.04	7.39	7.77	8.17	8.58	9.02	9.47	9.95	10.46	10.99	11.55	12.14	12.75	13.40		14.08		14.80		
11	16	El Paso	Yes	No	7.5%	60.1%	0.00	(37.97)	1.11	1.17	1.23	1.29	1.35	1.41	1.49	1.57	1.66	1.75	1.84	1.94	2.03	2.14	2.25	2.36	2.48	2.61	2.74	2.88	3.02	3.18	3.34	3.51	3.69	3.87	4.07	4.28	4.50	4.72	143.41	4.96	138.45		16	11
				e					2.30	2.05	2.19	2.34	2.50	2.66	2.72	2.78	2.84	2.90	2.96	3.11	3.27	3.44	3.61	3.80	3.99	4.19	4.40	4.63	4.86	5.11	5.37	5.64	5.93	6.23	6.55	6.88	7.23	7.60		7.98		8.39		
12	18	Entergy	Yes	No	8.5%	55.0%	0.00	(80.57)	3.32	3.32	3.47	3.63	3.80	3.97	4.08	4.20	4.32	4.44	4.56	4.79	5.04	5.29	5.56	5.84	6.14	6.45	6.78	7.12	7.49	7.87	8.27	8.69	9.13	9.59	10.08	10.59	11.13	11.69	348.57	12.29	336.29		18	12
				e					5.90	5.45	5.85	6.29	6.75	7.21	7.49	7.78	8.08	8.38	8.70	9.14	9.60	10.09	10.61	11.14	11.71	12.31	12.93	13.59	14.28	15.00	15.76	16.57	17.41	18.29	19.22	20.20	21.22	22.30		23.43		24.62		
13	21	Great Plains	Yes	Yes	9.0%	60.8%	0.00	(27.38)	0.94	1.00	1.06	1.13	1.20	1.27	1.35	1.44	1.53	1.62	1.72	1.81	1.90	1.99	2.10	2.20	2.31	2.43	2.55	2.68	2.82	2.96	3.11	3.27	3.44	3.61	3.80	3.99	4.19	4.41	148.48	4.63	143.85		21	13
				e					1.55	1.60	1.72	1.86	2.00	2.14	2.28	2.42	2.56	2.72	2.88	3.02	3.18	3.34	3.51	3.68	3.87	4.07	4.28	4.49	4.72	4.96	5.21	5.48	5.76	6.05	6.36	6.68	7.02	7.37		7.75		8.14		
14	23	IDACORP	Yes	Yes	7.2%	53.1%	0.00	(63.62)	1.76	1.90	2.00	2.10	2.20	2.30	2.47	2.65	2.84	3.04	3.25	3.41	3.58	3.77	3.96	4.16	4.37	4.59	4.83	5.07	5.33	5.60	5.88	6.18	6.50	6.83	7.17	7.54	7.92	8.32	199.79	8.75	191.05		23	14
				e					3.75	3.60	3.65	3.70	3.75	3.80	3.84	3.87	3.91	3.94	3.98	4.18	4.39	4.62	4.85	5.10	5.36	5.63	5.91	6.21	6.53	6.86	7.21	7.58	7.96	8.36	8.79	9.24	9.71	10.20		10.72		11.26		
15	26	MGE	Yes	No	8.4%	90.6%	(0.00)	(43.54)	1.11	1.15	1.20	1.25	1.30	1.35	1.41	1.46	1.52	1.59	1.65	1.73	1.82	1.91	2.01	2.11	2.22	2.33	2.45	2.57	2.71	2.84	2.99	3.14	3.30	3.47	3.64	3.83	4.02	4.23	297.25	4.44	292.81		26	15
				e					2.25	2.40	2.64	2.91	3.20	3.49	3.81	4.16	4.53	4.92	5.34	5.62	5.90	6.20	6.52	6.85	7.20	7.56	7.94	8.35	8.77	9.22	9.69	10.18	10.70	11.24	11.81	12.41	13.04	13.70		14.40		15.13		
16	31	OGE	Yes	No	9.3%	54.8%	0.00	(33.12)	0.93	1.05	1.16	1.27	1.40	1.53	1.69	1.87	2.07	2.28	2.51	2.64	2.77	2.91	3.06	3.22	3.38	3.55	3.73	3.92	4.12	4.33	4.55	4.78	5.02	5.28	5.55	5.83	6.12	6.43	174.61	6.76	167.85		31	16
				e					1.95	2.10	2.23	2.36	2.50	2.64	2.80	2.96	3.13	3.31	3.49	3.67	3.85	4.05	4.26	4.47	4.70	4.94	5.19	5.45	5.73	6.02	6.33	6.65	6.99	7.34	7.71	8.11	8.52	8.95		9.40		9.88		
17	32	Otter Tail	Yes	Yes	8.9%	78.3%	0.00	(31.80)	1.21	1.23	1.25	1.28	1.30	1.32	1.35	1.37	1.39	1.42	1.44	1.51	1.59	1.67	1.76	1.85	1.94	2.04	2.14	2.25	2.36	2.48	2.61	2.74	2.88	3.03	3.18	3.34	3.51	3.69	210.94	3.88	207.06		32	17
				e					1.75	1.85	1.99	2.14	2.30	2.46	2.73	3.01	3.32	3.66	4.02	4.23	4.44	4.67	4.91	5.16	5.42	5.69	5.98	6.29	6.61	6.94	7.29	7.66	8.05	8.46	8.89	9.34	9.82	10.32		10.84		11.39		
18	34	PG&E	Yes	Yes	8.2%	70.0%	0.00	(54.87)	1.82	1.82	1.91	2.00	2.10	2.20	2.26	2.33	2.40	2.47	2.55	2.68	2.81	2.96	3.11	3.26	3.43	3.60	3.79	3.98	4.18	4.39	4.62	4.85	5.10	5.36	5.63	5.92	6.22	6.53	277.99	6.86	271.13		34	18
				e					3.15	2.95	3.12	3.31	3.50	3.69	4.01	4.35	4.71	5.09	5.50	5.78	6.07	6.38	6.70	7.04	7.40	7.78	8.17	8.59	9.02	9.48	9.96	10.47	11.00	11.56	12.15	12.77	13.41	14.10		14.81		15.56		
19	35	PGE	Yes	No	8.1%	64.2%	0.00	(37.46)	1.11	1.17	1.24	1.32	1.40	1.48	1.56	1.64	1.73	1.82	1.91	2.01	2.11	2.22	2.33	2.45	2.58	2.71	2.84	2.99	3.14	3.30	3.47	3.64	3.83	4.02	4.23	4.44	4.67	4.91	171.16	5.16	166.01		35	19
				e					2.15	2.25	2.33	2.41	2.50	2.59	2.73	2.88	3.03	3.20	3.37	3.54	3.72	3.91	4.10	4.31	4.53	4.76	5.00	5.26	5.52	5.81	6.10	6.41	6.74	7.08	7.44	7.82	8.21	8.63		9.07		9.53		
20	36	Pinnacle	Yes	No	8.3%	55.0%	0.00	(65.45)	2.30	2.44	2.55	2.67	2.80	2.93	3.07	3.23	3.39	3.56	3.73	3.92	4.12	4.33	4.55	4.78	5.02	5.28	5.55	5.83	6.12	6.43	6.76	7.10	7.47	7.84	8.24	8.66	9.10	9.56	269.28	10.05	259.23		36	20
				e					3.70	3.85	3.98	4.11	4.25	4.39	4.54	4.69	4.85	5.01	5.18	5.44	5.72	6.01	6.31	6.63	6.97	7.32	7.69	8.09	8.50	8.93	9.38	9.86	10.36	10.89	11.44	12.02	12.63	13.27		13.95		14.65		
21	37	PNM	No	Yes	10.3%	72.2%	0.00	(28.84)	0.74	0.80	0.90	1.02	1.15	1.28	1.44	1.61	1.80	2.01	2.23	2.35	2.47	2.59	2.72	2.86	3.01	3.16	3.32	3.49	3.67	3.85	4.05	4.25	4.47	4.70	4.94	5.19	5.45	5.73	245.52	6.02	239.50		37	21
				e					1.50	1.55	1.78	2.05	2.35	2.65	2.95	3.27	3.62	3.99	4.40	4.62	4.86	5.10	5.36	5.64	5.92	6.22	6.54	6.87	7.22	7.59	7.97	8.38	8.80	9.25	9.72	10.22	10.73	11.28		11.85		12.46		
22	39	Public Serv.	Yes	No	7.6%	69.4%	0.00	(41.52)	1.48	1.52	1.53	1.54	1.55	1.56	1.58	1.61	1.63	1.65	1.68	1.76	1.85	1.95	2.04	2.15	2.26	2.37	2.49	2.62	2.75	2.89	3.04	3.19	3.35	3.53	3.70	3.89	4.09	4.30	184.16	4.52	179.64		39	22
				e					2.50	2.65	2.76	2.88	3.00	3.12	3.25	3.39	3.53	3.67	3.82	4.02	4.22	4.43	4.66	4.90	5.14	5.41	5.68	5.97	6.27	6.59	6.92	7.28	7.65	8.03	8.44	8.87	9.32	9.80		10.29		10.82		
23	40	SCANA	Yes	No	7.9%	61.0%	0.00	(58.09)	2.08	2.16	2.22	2.28	2.35	2.42	2.49	2.57	2.65	2.73	2.82	2.96	3.11	3.27	3.44	3.61	3.79	3.99	4.19	4.40	4.63	4.86	5.11	5.37	5.64	5.93	6.23	6.54	6.88	7.23	242.44	7.59	234.85		40	23
				e					3.80	3.90	4.01	4.13	4.25	4.37	4.57	4.77	4.98	5.20	5.43	5.70	5.99	6.30	6.62	6.95	7.31	7.68	8.07	8.48	8.91	9.36	9.83	10.33	10.86	11.41	11.99	12.60	13.24	13.91		14.62		15.36		
24	41	Sempra	Yes	No	8.2%	85.7%	0.00	(109.37)	2.61	2.76	2.90	3.05	3.20	3.35	3.54	3.74	3.94	4.16	4.38	4.61	4.84	5.09	5.34	5.62	5.90	6.20	6.52	6.85	7.19	7.56	7.94	8.35	8.77	9.22	9.69	10.18	10.69	11.24	673.85	11.81	662.04		41	24
				e					4.55	4.75	5.21	5.70	6.25	6.80	7.32	7.87	8.45	9.07	9.73	10.22	10.74	11.29	11.86	12.46	13.10	13.76	14.46	15.20	15.97	16.78	17.63	18.53	19.47	20.46	21.50	22.59	23.74	24.94		26.21		27.54		
25	42	Southern	Yes	No	8.8%	50.7%	0.00	(46.84)	2.08	2.15	2.22	2.29	2.36	2.43	2.51	2.60	2.69	2.77	2.87	3.01	3.16	3.33	3.49	3.67	3.86	4.05	4.26	4.48	4.70	4.94	5.19	5.46	5.74	6.03	6.33	6.65	6.99	7.35	199.19	7.72	191.47		42	25
				e					2.80	2.90	3.01	3.13	3.25	3.37	3.50	3.63	3.76	3.90	4.04	4.25	4.46	4.69	4.93	5.18	5.44	5.72	6.01	6.32	6.64	6.97	7.33	7.70	8.09	8.50	8.93	9.39	9.86	10.37		10.89		11.45		
26	46	Vectren	Yes	No	9.1%	80.1%	0.00	(45.16)	1.46	1.54	1.61	1.68	1.75	1.82	1.90	1.98	2.07	2.15	2.24	2.36	2.48	2.60	2.73	2.87	3.02	3.17	3.33	3.50	3.68	3.87	4.06	4.27	4.49	4.72	4.95	5.21	5.47	5.75	324.57	6.04	318.53		46	26
				e					2.05	2.40	2.59	2.78	3.00	3.22	3.54	3.89	4.27	4.67	5.11	5.37	5.64	5.93	6.23	6.54	6.88	7.23	7.59	7.98	8.38	8.81	9.26	9.73	10.22	10.74	11.29	11.86	12.46	13.10		13.76		14.46		
27	47	Westar	Yes	Yes	8.3%	65.5%	0.00	(39.49)	1.39	1.44	1.49	1.54	1.60	1.66	1.71	1.78	1.84	1.90	1.97	2.07	2.18	2.29	2.40	2.53	2.65	2.79	2.93	3.08	3.24	3.40	3.57	3.75	3.95	4.15	4.36	4.58	4.81	5.05	193.19	5.31	187.88		47	27
				e					2.35	2.45	2.59	2.74	2.90	3.06	3.22	3.39	3.57	3.76	3.95	4.15	4.36	4.58	4.82	5.06	5.32	5.59	5.87	6.17	6.48	6.81	7.16	7.52	7.90	8.30	8.73	9.17	9.64	10.13		10.64		11.18		
28	49	Xcel	Yes	No	8.6%	64.6%	0.00	(35.63)	1.18	1.26	1.32	1.38	1.45	1.52	1.60	1.69	1.78	1.88	1.98	2.08	2.19	2.30	2.42	2.54	2.67	2.81	2.95	3.10	3.26	3.42	3.60	3.78	3.97	4.17	4.38	4.61	4.84	5.09	186.58	5.35	181.23		49	28
				e					1.95	2.05	2.19	2.34	2.50	2.66	2.81	2.98	3.14	3.32	3.50	3.68	3.87	4.07	4.27	4.49	4.72	4.96	5.21	5.47	5.75	6.04	6.35	6.67	7.01	7.37	7.74	8.14	8.55	8.98		9.44		9.92		
		TOTALS	27	9		Mean																																						
				3	8.5%	56.8%	0.0%	Staff																																				
					8.9%	62.1%	0.0%	Staff (Mid Cap Sensitivity)																																				
					8.4%	63.4%	0.0%	Staff (Co Peer Sensitivity)																																				

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B.O.Y. Cash Flows | **Staff** | **Model** | **Y** | **EPS Growth**

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42		
						Terminal Value as			2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2043					
	#	Abbreviated Utility	PGE	Staff	IRR	% of NPV$_{DIV}$	NPV @ IRR	Recent Price*	Initial Stage						Transition Stage					Final Stage																			Terminal Value	2044 Div	2044 Sale	2043	#	
1	1	AEP	Yes	Yes	8.6%	54.9%	0.00	(58.52)	2.15	2.26	2.38	2.50	2.62	2.76	2.90	3.05	3.21	3.37	3.54	3.72	3.91	4.11	4.32	4.54	4.77	5.01	5.27	5.54	5.82	6.11	6.42	6.75	7.09	7.45	7.83	8.23	8.65	9.09	261.11	9.55	251.56		1	1
				e					3.45	3.50	3.66	3.83	4.00	4.17	4.37	4.58	4.79	5.01	5.24	5.50	5.78	6.08	6.39	6.71	7.05	7.41	7.79	8.18	8.60	9.04	9.49	9.98	10.48	11.02	11.58	12.16	12.78	13.43		14.11		14.83		
2	2	Allete	Yes	No	8.9%	65.4%	0.00	(54.54)	2.04	2.12	2.21	2.30	2.39	2.49	2.59	2.69	2.80	2.91	3.06	3.21	3.37	3.55	3.73	3.91	4.11	4.32	4.54	4.77	5.02	5.27	5.54	5.82	6.12	6.43	6.75	7.10	7.46	7.83	307.35	8.23	299.12		2	2
				e					2.85	3.20	3.37	3.56	3.75	3.94	4.23	4.52	4.84	5.17	5.52	5.80	6.10	6.41	6.73	7.07	7.43	7.81	8.21	8.62	9.06	9.52	10.01	10.51	11.05	11.61	12.20	12.82	13.47	14.15		14.87		15.63		
3	3	Alliant	Yes	No	9.2%	50.0%	0.00	(64.30)	2.20	2.38	2.58	2.80	3.02	3.27	3.53	3.81	4.12	4.44	4.66	4.90	5.15	5.41	5.68	5.97	6.27	6.59	6.93	7.28	7.65	8.04	8.45	8.88	9.33	9.80	10.30	10.82	11.37	11.95	297.31	12.56	284.75		3	3
				e					3.45	3.60	3.76	3.93	4.10	4.27	4.48	4.70	4.92	5.16	5.40	5.67	5.96	6.26	6.58	6.91	7.27	7.63	8.02	8.43	8.86	9.31	9.78	10.28	10.80	11.35	11.92	12.53	13.17	13.84		14.54		15.28		
4	4	Ameren	Yes	No	8.5%	65.4%	0.00	(42.94)	1.65	1.70	1.75	1.80	1.85	1.90	1.94	1.99	2.04	2.09	2.19	2.30	2.42	2.54	2.67	2.81	2.95	3.10	3.26	3.43	3.60	3.78	3.97	4.18	4.39	4.61	4.85	5.09	5.35	5.62	221.19	5.91	215.29		4	4
				e					2.35	2.55	2.69	2.84	3.00	3.16	3.34	3.53	3.73	3.94	4.16	4.37	4.60	4.83	5.07	5.33	5.60	5.89	6.19	6.50	6.83	7.18	7.54	7.93	8.33	8.75	9.20	9.66	10.16	10.67		11.21		11.78		
5	7	CenterPoint	Yes	No	11.2%	40.7%	0.00	(21.54)	1.03	1.11	1.20	1.30	1.40	1.52	1.65	1.79	1.94	2.10	2.21	2.32	2.44	2.57	2.70	2.83	2.98	3.13	3.29	3.45	3.63	3.81	4.01	4.21	4.42	4.65	4.89	5.13	5.39	5.67	127.97	5.96	122.01		7	5
				e					1.30	1.30	1.44	1.58	1.75	1.92	2.04	2.17	2.31	2.45	2.60	2.73	2.87	3.02	3.17	3.33	3.50	3.68	3.87	4.06	4.27	4.49	4.71	4.95	5.21	5.47	5.75	6.04	6.35	6.67		7.01		7.36		
6	10	CMS	Yes	No	8.7%	65.9%	0.00	(35.33)	1.14	1.21	1.28	1.35	1.42	1.51	1.60	1.69	1.79	1.89	1.99	2.09	2.20	2.31	2.43	2.55	2.68	2.81	2.96	3.11	3.26	3.43	3.61	3.79	3.98	4.18	4.40	4.62	4.85	5.10	193.21	5.36	187.85		10	6
				e					1.75	1.85	1.97	2.11	2.25	2.39	2.55	2.72	2.90	3.09	3.29	3.45	3.63	3.81	4.01	4.21	4.43	4.65	4.89	5.13	5.40	5.67	5.96	6.26	6.58	6.91	7.26	7.63	8.02	8.43		8.86		9.31		
7	11	Consol. Ed.	Yes	No	7.8%	53.2%	0.00	(64.28)	2.58	2.64	2.69	2.75	2.81	2.87	2.94	3.01	3.07	3.14	3.30	3.47	3.65	3.83	4.03	4.23	4.45	4.67	4.91	5.16	5.42	5.70	5.99	6.29	6.61	6.94	7.30	7.67	8.06	8.47	231.15	8.90	222.26		11	7
				e					3.90	3.95	4.05	4.15	4.25	4.35	4.43	4.51	4.60	4.68	4.76	5.01	5.26	5.53	5.81	6.10	6.41	6.74	7.08	7.44	7.82	8.22	8.63	9.07	9.53	10.02	10.53	11.06	11.62	12.21		12.83		13.48		
8	12	Dominion	Yes	No	8.2%	62.4%	0.00	(72.85)	2.50	2.60	2.70	2.80	2.90	3.04	3.18	3.32	3.47	3.63	3.81	4.00	4.21	4.42	4.65	4.88	5.13	5.39	5.66	5.95	6.25	6.57	6.91	7.26	7.63	8.01	8.42	8.85	9.30	9.77	336.36	10.27	326.10		12	8
				e					3.40	3.65	3.76	3.88	4.00	4.12	4.35	4.59	4.84	5.10	5.38	5.65	5.94	6.24	6.55	6.89	7.24	7.61	7.99	8.40	8.82	9.27	9.74	10.24	10.76	11.31	11.88	12.48	13.12	13.78		14.48		15.22		
9	13	DTE	Yes	Yes	8.5%	60.0%	0.00	(83.39)	2.83	2.98	3.14	3.30	3.46	3.66	3.86	4.07	4.29	4.52	4.75	4.99	5.25	5.51	5.79	6.09	6.40	6.72	7.06	7.42	7.80	8.19	8.61	9.05	9.51	9.99	10.50	11.03	11.59	12.18	394.27	12.80	381.48		13	9
				e					4.45	4.55	4.77	5.01	5.25	5.49	5.80	6.13	6.47	6.82	7.19	7.56	7.94	8.34	8.77	9.21	9.68	10.17	10.69	11.23	11.80	12.40	13.03	13.70	14.39	15.12	15.89	16.70	17.55	18.44		19.37		20.36		
10	15	Edison Int'l	Yes	Yes	8.3%	50.8%	0.00	(64.73)	1.71	1.87	2.05	2.25	2.45	2.71	3.01	3.32	3.67	4.04	4.24	4.46	4.68	4.92	5.17	5.43	5.71	6.00	6.31	6.63	6.96	7.32	7.69	8.08	8.49	8.92	9.37	9.85	10.35	10.88	250.90	11.43	239.47		15	10
				e					4.00	3.75	3.98	4.23	4.50	4.77	4.85	4.95	5.04	5.13	5.23	5.49	5.77	6.07	6.37	6.70	7.04	7.39	7.77	8.17	8.58	9.02	9.47	9.95	10.46	10.99	11.55	12.14	12.75	13.40		14.08		14.80		
11	16	El Paso	Yes	No	7.7%	57.9%	0.00	(37.97)	1.17	1.23	1.29	1.35	1.41	1.49	1.57	1.66	1.75	1.84	1.94	2.03	2.14	2.25	2.36	2.48	2.61	2.74	2.88	3.02	3.18	3.34	3.51	3.69	3.87	4.07	4.28	4.50	4.72	4.96	143.66	5.22	138.45		16	11
				e					2.30	2.05	2.19	2.34	2.50	2.66	2.72	2.78	2.84	2.90	2.96	3.11	3.27	3.44	3.61	3.80	3.99	4.19	4.40	4.63	4.86	5.11	5.37	5.64	5.93	6.23	6.55	6.88	7.23	7.60		7.98		8.39		
12	18	Entergy	Yes	No	8.6%	53.0%	0.00	(80.57)	3.32	3.47	3.63	3.80	3.97	4.08	4.20	4.32	4.44	4.56	4.79	5.04	5.29	5.56	5.84	6.14	6.45	6.78	7.12	7.49	7.87	8.27	8.69	9.13	9.59	10.08	10.59	11.13	11.69	12.29	349.20	12.91	336.29		18	12
				e					5.90	5.45	5.85	6.29	6.75	7.21	7.49	7.78	8.08	8.38	8.70	9.14	9.60	10.09	10.61	11.14	11.71	12.31	12.93	13.59	14.28	15.00	15.76	16.57	17.41	18.29	19.22	20.20	21.22	22.30		23.43		24.62		
13	21	Great Plains	Yes	Yes	9.2%	58.1%	0.00	(27.38)	1.00	1.06	1.13	1.20	1.27	1.35	1.44	1.53	1.62	1.72	1.81	1.90	1.99	2.10	2.20	2.31	2.43	2.55	2.68	2.82	2.96	3.11	3.27	3.44	3.61	3.80	3.99	4.19	4.41	4.63	148.72	4.87	143.85		21	13
				e					1.55	1.60	1.72	1.86	2.00	2.14	2.28	2.42	2.56	2.72	2.88	3.02	3.18	3.34	3.51	3.68	3.87	4.07	4.28	4.49	4.72	4.96	5.21	5.48	5.76	6.05	6.36	6.68	7.02	7.37		7.75		8.14		
14	23	IDACORP	Yes	Yes	7.4%	50.8%	0.00	(63.62)	1.90	2.00	2.10	2.20	2.30	2.47	2.65	2.84	3.04	3.25	3.41	3.58	3.77	3.96	4.16	4.37	4.59	4.83	5.07	5.33	5.60	5.88	6.18	6.50	6.83	7.17	7.54	7.92	8.32	8.75	200.24	9.19	191.05		23	14
				e					3.75	3.60	3.65	3.70	3.75	3.80	3.84	3.87	3.91	3.94	3.98	4.18	4.39	4.62	4.85	5.10	5.36	5.63	5.91	6.21	6.53	6.86	7.21	7.58	7.96	8.36	8.79	9.24	9.71	10.20		10.72		11.26		
15	26	MGE	Yes	No	8.5%	88.6%	0.00	(43.54)	1.15	1.20	1.25	1.30	1.35	1.41	1.46	1.52	1.59	1.65	1.73	1.82	1.91	2.01	2.11	2.22	2.33	2.45	2.57	2.71	2.84	2.99	3.14	3.30	3.47	3.64	3.83	4.02	4.23	4.44	297.47	4.67	292.81		26	15
				e					2.25	2.40	2.64	2.91	3.20	3.49	3.81	4.16	4.53	4.92	5.34	5.62	5.90	6.20	6.52	6.85	7.20	7.56	7.94	8.35	8.77	9.22	9.69	10.18	10.70	11.24	11.81	12.41	13.04	13.70		14.40		15.13		
16	31	OGE	Yes	No	9.6%	51.5%	0.00	(33.12)	1.05	1.16	1.27	1.40	1.53	1.69	1.87	2.07	2.28	2.51	2.64	2.77	2.91	3.06	3.22	3.38	3.55	3.73	3.92	4.12	4.33	4.55	4.78	5.02	5.28	5.55	5.83	6.12	6.43	6.76	174.95	7.10	167.85		31	16
				e					1.95	2.10	2.23	2.36	2.50	2.64	2.80	2.96	3.13	3.31	3.49	3.67	3.85	4.05	4.26	4.47	4.70	4.94	5.19	5.45	5.73	6.02	6.33	6.65	6.99	7.34	7.71	8.11	8.52	8.95		9.40		9.88		
17	32	Otter Tail	Yes	Yes	9.0%	76.7%	0.00	(31.80)	1.23	1.25	1.28	1.30	1.32	1.35	1.37	1.39	1.42	1.44	1.51	1.59	1.67	1.76	1.85	1.94	2.04	2.14	2.25	2.36	2.48	2.61	2.74	2.88	3.03	3.18	3.34	3.51	3.69	3.88	211.14	4.08	207.06		32	17
				e					1.75	1.85	1.99	2.14	2.30	2.46	2.73	3.01	3.32	3.66	4.02	4.23	4.44	4.67	4.91	5.16	5.42	5.69	5.98	6.29	6.61	6.94	7.29	7.66	8.05	8.46	8.89	9.34	9.82	10.32		10.84		11.39		
18	34	PG&E	Yes	Yes	8.3%	68.0%	0.00	(54.87)	1.82	1.91	2.00	2.10	2.20	2.26	2.33	2.40	2.47	2.55	2.68	2.81	2.96	3.11	3.26	3.43	3.60	3.79	3.98	4.18	4.39	4.62	4.85	5.10	5.36	5.63	5.92	6.22	6.53	6.86	278.34	7.21	271.13		34	18
				e					3.15	2.95	3.12	3.31	3.50	3.69	4.01	4.35	4.71	5.09	5.50	5.78	6.07	6.38	6.70	7.04	7.40	7.78	8.17	8.59	9.02	9.48	9.96	10.47	11.00	11.56	12.15	12.77	13.41	14.10		14.81		15.56		
19	35	PGE	Yes	No	8.2%	61.8%	0.00	(37.46)	1.17	1.24	1.32	1.40	1.48	1.56	1.64	1.73	1.82	1.91	2.01	2.11	2.22	2.33	2.45	2.58	2.71	2.84	2.99	3.14	3.30	3.47	3.64	3.83	4.02	4.23	4.44	4.67	4.91	5.16	171.42	5.42	166.01		35	19
				e					2.15	2.25	2.33	2.41	2.50	2.59	2.73	2.88	3.03	3.20	3.37	3.54	3.72	3.91	4.10	4.31	4.53	4.76	5.00	5.26	5.52	5.81	6.10	6.41	6.74	7.08	7.44	7.82	8.21	8.63		9.07		9.53		
20	36	Pinnacle	Yes	No	8.4%	52.8%	0.00	(65.45)	2.44	2.55	2.67	2.80	2.93	3.07	3.23	3.39	3.56	3.73	3.92	4.12	4.33	4.55	4.78	5.02	5.28	5.55	5.83	6.12	6.43	6.76	7.10	7.47	7.84	8.24	8.66	9.10	9.56	10.05	269.79	10.56	259.23		36	20
				e					3.70	3.85	3.98	4.11	4.25	4.39	4.54	4.69	4.85	5.01	5.18	5.44	5.72	6.01	6.31	6.63	6.97	7.32	7.69	8.09	8.50	8.93	9.38	9.86	10.36	10.89	11.44	12.02	12.63	13.27		13.95		14.65		
21	37	PNM	No	Yes	10.5%	68.3%	0.00	(28.84)	0.80	0.90	1.02	1.15	1.28	1.44	1.61	1.80	2.01	2.23	2.35	2.47	2.59	2.72	2.86	3.01	3.16	3.32	3.49	3.67	3.85	4.05	4.25	4.47	4.70	4.94	5.19	5.45	5.73	6.02	245.82	6.32	239.50		37	21
				e					1.50	1.55	1.78	2.05	2.35	2.65	2.95	3.27	3.62	3.99	4.40	4.62	4.86	5.10	5.36	5.64	5.92	6.22	6.54	6.87	7.22	7.59	7.97	8.38	8.80	9.25	9.72	10.22	10.73	11.28		11.85		12.46		
22	39	Public Serv.	Yes	No	7.7%	67.9%	0.00	(41.52)	1.52	1.53	1.54	1.55	1.56	1.58	1.61	1.63	1.65	1.68	1.76	1.85	1.95	2.04	2.15	2.26	2.37	2.49	2.62	2.75	2.89	3.04	3.19	3.35	3.53	3.70	3.89	4.09	4.30	4.52	184.39	4.75	179.64		39	22
				e					2.50	2.65	2.76	2.88	3.00	3.12	3.25	3.39	3.53	3.67	3.82	4.02	4.22	4.43	4.66	4.90	5.14	5.41	5.68	5.97	6.27	6.59	6.92	7.28	7.65	8.03	8.44	8.87	9.32	9.80		10.29		10.82		
23	40	SCANA	Yes	No	8.0%	59.1%	0.00	(58.09)	2.16	2.22	2.28	2.35	2.42	2.49	2.57	2.65	2.73	2.82	2.96	3.11	3.27	3.44	3.61	3.79	3.99	4.19	4.40	4.63	4.86	5.11	5.37	5.64	5.93	6.23	6.54	6.88	7.23	7.59	242.82	7.98	234.85		40	23
				e					3.80	3.90	4.01	4.13	4.25	4.37	4.57	4.77	4.98	5.20	5.43	5.70	5.99	6.30	6.62	6.95	7.31	7.68	8.07	8.48	8.91	9.36	9.83	10.33	10.86	11.41	11.99	12.60	13.24	13.91		14.62		15.36		
24	41	Sempra	Yes	No	8.3%	83.5%	0.00	(109.37)	2.76	2.90	3.05	3.20	3.35	3.54	3.74	3.94	4.16	4.38	4.61	4.84	5.09	5.34	5.62	5.90	6.20	6.52	6.85	7.19	7.56	7.94	8.35	8.77	9.22	9.69	10.18	10.69	11.24	11.81	674.44	12.41	662.04		41	24
				e					4.55	4.75	5.21	5.70	6.25	6.80	7.32	7.87	8.45	9.07	9.73	10.22	10.74	11.29	11.86	12.46	13.10	13.76	14.46	15.20	15.97	16.78	17.63	18.53	19.47	20.46	21.50	22.59	23.74	24.94		26.21		27.54		
25	42	Southern	Yes	No	8.9%	48.7%	0.00	(46.84)	2.15	2.22	2.29	2.36	2.43	2.51	2.60	2.69	2.77	2.87	3.01	3.16	3.33	3.49	3.67	3.86	4.05	4.26	4.48	4.70	4.94	5.19	5.46	5.74	6.03	6.33	6.65	6.99	7.35	7.72	199.59	8.11	191.47		42	25
				e					2.80	2.90	3.01	3.13	3.25	3.37	3.50	3.63	3.76	3.90	4.04	4.25	4.46	4.69	4.93	5.18	5.44	5.72	6.01	6.32	6.64	6.97	7.33	7.70	8.09	8.50	8.93	9.39	9.86	10.37		10.89		11.45		
26	46	Vectren	Yes	No	9.2%	77.8%	0.00	(45.16)	1.54	1.61	1.68	1.75	1.82	1.90	1.98	2.07	2.15	2.24	2.36	2.48	2.60	2.73	2.87	3.02	3.17	3.33	3.50	3.68	3.87	4.06	4.27	4.49	4.72	4.95	5.21	5.47	5.75	6.04	324.88	6.35	318.53		46	26
				e					2.05	2.40	2.59	2.78	3.00	3.22	3.54	3.89	4.27	4.67	5.11	5.37	5.64	5.93	6.23	6.54	6.88	7.23	7.59	7.98	8.38	8.81	9.26	9.73	10.22	10.74	11.29	11.86	12.46	13.10		13.76		14.46		
27	47	Westar	Yes	Yes	8.4%	63.4%	0.00	(39.49)	1.44	1.49	1.54	1.60	1.66	1.71	1.78	1.84	1.90	1.97	2.07	2.18	2.29	2.40	2.53	2.65	2.79	2.93	3.08	3.24	3.40	3.57	3.75	3.95	4.15	4.36	4.58	4.81	5.05	5.31	193.46	5.58	187.88		47	27
				e					2.35	2.45	2.59	2.74	2.90	3.06	3.22	3.39	3.57	3.76	3.95	4.15	4.36	4.58	4.82	5.06	5.32	5.59	5.87	6.17	6.48	6.81	7.16	7.52	7.90	8.30	8.73	9.17	9.64	10.13		10.64		11.18		
28	49	Xcel	Yes	No	8.8%	62.1%	0.00	(35.63)	1.26	1.32	1.38	1.45	1.52	1.60	1.69	1.78	1.88	1.98	2.08	2.19	2.30	2.42	2.54	2.67	2.81	2.95	3.10	3.26	3.42	3.60	3.78	3.97	4.17	4.38	4.61	4.84	5.09	5.35	186.85	5.62	181.23		49	28
				e					1.95	2.05	2.19	2.34	2.50	2.66	2.81	2.98	3.14	3.32	3.50	3.68	3.87	4.07	4.27	4.49	4.72	4.96	5.21	5.47	5.75	6.04	6.35	6.67	7.01	7.37	7.74	8.14	8.55	8.98		9.44		9.92		
		TOTALS	27	9		Mean																																						
				3	8.7%	54.8%	0.0%	Staff																																				
					9.1%	59.1%	0.0%	Staff (Mid Cap Sensitivity)																																				
					8.6%	61.1%	0.0%	Staff (Co Peer Sensitivity)																																				

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Average B.O.Y. & E.O.Y. Cash Flows Model Y **EPS Growth**

	1	2	3	4	5	6	7	8	9	
	#	Abbreviated Utility	PGE	Staff	Average IRR	Terminal Value as % of NPV_{DIV}	Average 2014 - 2019 Dividend Growth Rates EOY			
1	1	AEP	Yes	Yes	8.5%	56.1%	5.1%	5.1%	5.1%	
2	2	Allete	Yes	No	8.8%	66.5%	4.0%	4.0%	4.0%	
3	3	Alliant	Yes	No	9.0%	51.4%	8.2%	8.2%	8.2%	
4	4	Ameren	Yes	No	8.5%	66.3%	2.9%	2.8%	2.9%	
5	7	CenterPoint	Yes	No	11.0%	42.2%	7.9%	8.1%	8.0%	
6	10	CMS	Yes	No	8.7%	67.2%	5.7%	5.8%	5.7%	
7	11	Consol. Ed.	Yes	No	7.8%	54.0%	2.1%	2.2%	2.2%	
8	12	Dominion	Yes	No	8.2%	63.5%	3.8%	4.0%	3.9%	
9	13	DTE	Yes	Yes	8.4%	61.2%	5.2%	5.3%	5.2%	
10	15	Edison Int'l	Yes	Yes	8.2%	52.4%	9.4%	9.7%	9.5%	
11	16	El Paso	Yes	No	7.6%	59.0%	4.8%	5.0%	4.9%	
12	18	Entergy	Yes	No	8.6%	54.0%	4.6%	4.1%	4.3%	
13	21	Great Plains	Yes	Yes	9.1%	59.5%	6.2%	6.2%	6.2%	
14	23	IDACORP	Yes	Yes	7.3%	51.9%	4.9%	5.5%	5.2%	
15	26	MGE	Yes	No	8.4%	89.6%	4.1%	4.1%	4.1%	
16	31	OGE	Yes	No	9.5%	53.2%	9.8%	10.0%	9.9%	
17	32	Otter Tail	Yes	Yes	8.9%	77.5%	1.9%	1.8%	1.8%	
18	34	PG&E	Yes	Yes	8.2%	69.0%	4.8%	4.4%	4.6%	
19	35	**PGE**	Yes	No	8.1%	63.0%	6.0%	5.8%	5.9%	
20	36	Pinnacle	Yes	No	8.4%	53.9%	4.6%	4.7%	4.7%	
21	37	PNM	No	Yes	10.4%	70.2%	12.5%	12.4%	12.4%	
22	39	Public Serv.	Yes	No	7.7%	68.7%	0.7%	0.9%	0.8%	
23	40	SCANA	Yes	No	8.0%	60.1%	2.8%	2.9%	2.9%	
24	41	Sempra	Yes	No	8.2%	84.6%	5.0%	5.1%	5.1%	
25	42	Southern	Yes	No	8.8%	49.7%	3.1%	3.2%	3.2%	
26	46	Vectren	Yes	No	9.2%	78.9%	4.3%	4.3%	4.3%	
27	47	Westar	Yes	Yes	8.4%	64.5%	3.5%	3.6%	3.5%	
28	49	Xcel	Yes	No	8.7%	63.3%	4.7%	4.9%	4.8%	
		TOTALS	**27**	**9**			**MEAN**			
				3	**8.39%**	55.8%	12.4%	6.0%	6.0%	Staff
					8.96%	60.6%	7.9%	8.0%	7.9%	Staff (Mid Cap Sensitivity)
					8.52%	62.3%	4.8%	4.9%	4.9%	Staff (Co Peer Sensitivity)

CASE: UE 294
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 204

Staff Synthetic Forward Curve TIPS Analysis

Exhibits in Support
of Opening Testimony

June 15, 2015

TIPs – Implied Average Annual Forward Inflation Rate

2024 through 2044 TIPs-Implied Average Annual Inflation Rate: **2.12%**

Yr. End		Individually Implied Price Levels					Implied Forward Curve/Price Level					Implied	
Mo.-Yr.	Years	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr	Price Level	Check
Dec-14	0	100.00	100.00	100.00	100.00	100.00	100.00					100.00	
Dec-15	1	101.41	101.61	101.83	101.95	102.02	101.41					101.41	
Dec-16	2	102.85	103.25	103.70	103.93	104.09	102.85					102.85	
Dec-17	3	104.30	104.91	105.60	105.95	106.19	104.30					104.30	
Dec-18	4	105.77	106.60	107.54	108.02	108.34	105.77					105.77	
Dec-19	5	107.27	108.31	109.51	110.12	110.53	107.27					107.27	
Dec-20	6		110.06	111.52	112.26	112.77		109.53				109.53	
Dec-21	7		111.83	113.56	114.45	115.05		111.83				111.83	
Dec-22	8			115.64	116.68	117.38			114.46			114.46	
Dec-23	9			117.76	118.95	119.76			117.16			117.16	
Dec-24	10			119.92	121.26	122.18			119.92			119.92	
Dec-25	11				123.62	124.65				122.39		122.39	122.46
Dec-26	12				126.03	127.17				124.91		124.91	125.06
Dec-27	13				128.48	129.75				127.49		127.49	127.71
Dec-28	14				130.99	132.37				130.11		130.11	130.41
Dec-29	15				133.54	135.05				132.79		132.79	133.17
Dec-30	16				136.13	137.78				135.53		135.53	136.00
Dec-31	17				138.78	140.57				138.32		138.32	138.88
Dec-32	18				141.49	143.41				141.17		141.17	141.82
Dec-33	19				144.24	146.32				144.08		144.08	144.82
Dec-34	20				147.05	149.28				147.05		147.05	147.89
Dec-35	21					152.30					150.25	150.25	151.02
Dec-36	22					155.38					153.52	153.52	154.22
Dec-37	23					158.52					156.86	156.86	157.49
Dec-38	24					161.73					160.28	160.28	160.83
Dec-39	25					165.00					163.77	163.77	164.23
Dec-40	26					168.34					167.33	167.33	167.71
Dec-41	27					171.75					170.97	170.97	171.27
Dec-42	28					175.22					174.69	174.69	174.89
Dec-43	29					178.77					178.50	178.50	178.60
Dec-44	30					182.38					182.38	182.38	182.38

Quarterly Aggregation of H15 Data

Average Quarterly Values for FRB H15 Data

See FRB H.15 Tab for Data Feed Sources.

Staff TIPS Analysis **Quarterly Aggregation**

Average Monthly Inflation Indexed Rates by Quarter

Qtr	TIPS-05m	TIPS-07m	TIPS-10m	TIPS-20m	TIPS-30m
2003-Q1	1.33	1.81	2.07		
2003-Q2	1.15	1.61	1.94		
2003-Q3	1.36	1.84	2.21		
2003-Q4	1.24	1.65	2.01		
2004-Q1	0.82	1.26	1.71		
2004-Q2	1.26	1.69	2.05		
2004-Q3	1.17	1.55	1.89	2.28	
2004-Q4	0.93	1.30	1.69	2.08	
2005-Q1	1.17	1.41	1.71	1.93	
2005-Q2	1.30	1.44	1.68	1.83	
2005-Q3	1.59	1.70	1.82	1.98	
2005-Q4	1.92	1.98	2.04	2.13	
2006-Q1	2.00	2.05	2.09	2.08	
2006-Q2	2.34	2.39	2.46	2.48	
2006-Q3	2.37	2.37	2.37	2.38	
2006-Q4	2.40	2.36	2.32	2.29	
2007-Q1	2.28	2.33	2.33	2.36	
2007-Q2	2.35	2.40	2.44	2.49	
2007-Q3	2.38	2.44	2.45	2.46	
2007-Q4	1.54	1.81	1.92	2.11	
2008-Q1	0.58	1.02	1.32	1.81	
2008-Q2	0.79	1.17	1.48	2.03	
2008-Q3	1.18	1.47	1.70	2.16	
2008-Q4	2.73	2.92	2.60	2.73	
2009-Q1	1.37	1.54	1.79	2.34	
2009-Q2	1.12	1.37	1.72	2.31	
2009-Q3	1.17	1.41	1.74	2.22	
2009-Q4	0.58	0.94	1.37	1.98	
2010-Q1	0.47	0.94	1.43	2.00	2.16
2010-Q2	0.46	0.91	1.36	1.77	1.88
2010-Q3	0.20	0.57	1.06	1.68	1.76
2010-Q4	-0.11	0.28	0.75	1.48	1.65
2011-Q1	0.07	0.67	1.09	1.71	2.00
2011-Q2	-0.29	0.33	0.80	1.49	1.78
2011-Q3	-0.65	-0.22	0.28	0.95	1.25
2011-Q4	-0.75	-0.39	0.05	0.61	0.85
2012-Q1	-1.02	-0.60	-0.17	0.51	0.78
2012-Q2	**-1.08**	**-0.75**	**-0.35**	**0.35**	**0.66**
2012-Q3	-1.27	-1.01	-0.63	0.02	0.43
2012-Q4	**-1.42**	**-1.15**	**-0.76**	**-0.02**	**0.36**
2013-Q1	-1.40	-0.98	-0.59	0.19	0.56
2013-Q2	**-1.04**	**-0.62**	**-0.25**	**0.47**	**0.80**
2013-Q3	-0.32	0.17	0.56	1.16	1.43
2013-Q4	**-0.29**	**0.25**	**0.57**	**1.19**	**1.50**
2014-Q1	-0.16	0.37	0.58	1.11	1.39
2014-Q2	**-0.25**	**0.27**	**0.43**	**0.88**	**1.44**
2014-Q3	-0.13	0.24	0.32	0.72	0.98
2014-Q4	**0.19**	**0.39**	**0.45**	**0.75**	**0.95**

Average Monthly Nominal UST Rates by Quarter

Qtr	UST-05m	UST-07m	UST-10m	UST-20m	UST-30m
2003-Q1	2.91	3.46	3.92	4.90	
2003-Q2	2.57	3.13	3.62	4.59	
2003-Q3	3.14	3.72	4.23	5.17	
2003-Q4	3.25	3.78	4.29	5.16	
2004-Q1	2.99	3.52	4.02	4.89	
2004-Q2	3.72	4.18	4.60	5.36	
2004-Q3	3.51	3.92	4.30	5.07	
2004-Q4	3.49	3.85	4.17	4.87	
2005-Q1	3.88	4.09	4.30	4.76	
2005-Q2	3.87	3.99	4.16	4.55	
2005-Q3	4.04	4.11	4.21	4.51	
2005-Q4	4.39	4.42	4.49	4.77	
2006-Q1	4.55	4.55	4.57	4.76	4.64
2006-Q2	4.99	5.02	5.07	5.29	5.14
2006-Q3	4.84	4.85	4.90	5.09	4.99
2006-Q4	4.60	4.60	4.63	4.83	4.74
2007-Q1	4.65	4.65	4.68	4.90	4.80
2007-Q2	4.76	4.79	4.85	5.07	4.99
2007-Q3	4.50	4.60	4.73	5.01	4.94
2007-Q4	3.79	3.98	4.26	4.65	4.61
2008-Q1	2.75	3.15	3.66	4.40	4.41
2008-Q2	3.16	3.46	3.89	4.59	4.58
2008-Q3	3.11	3.44	3.86	4.49	4.45
2008-Q4	2.18	2.63	3.25	3.97	3.68
2009-Q1	1.76	2.23	2.74	3.69	3.45
2009-Q2	2.23	2.88	3.31	4.19	4.17
2009-Q3	2.47	3.12	3.52	4.28	4.32
2009-Q4	2.30	2.98	3.46	4.27	4.33
2010-Q1	2.42	3.16	3.72	4.49	4.62
2010-Q2	2.25	2.93	3.49	4.20	4.37
2010-Q3	1.55	2.19	2.79	3.60	3.85
2010-Q4	1.49	2.18	2.86	3.84	4.16
2011-Q1	2.12	2.83	3.46	4.32	4.56
2011-Q2	1.86	2.55	3.21	4.07	4.34
2011-Q3	1.15	1.78	2.43	3.34	3.70
2011-Q4	0.95	1.50	2.05	2.75	3.04
2012-Q1	0.90	1.44	2.04	2.80	3.14
2012-Q2	**0.79**	**1.24**	**1.82**	**2.55**	**2.94**
2012-Q3	0.67	1.08	1.64	2.37	2.75
2012-Q4	**0.69**	**1.12**	**1.71**	**2.46**	**2.86**
2013-Q1	0.83	1.32	1.95	2.75	3.14
2013-Q2	**0.92**	**1.39**	**2.00**	**2.78**	**3.15**
2013-Q3	1.51	2.12	2.71	3.44	3.72
2013-Q4	**1.44**	**2.12**	**2.75**	**3.50**	**3.79**
2014-Q1	1.60	2.22	2.76	3.42	3.68
2014-Q2	**1.66**	**2.19**	**2.62**	**3.18**	**3.15**
2014-Q3	1.70	2.16	2.50	3.01	3.26
2014-Q4	**1.60**	**2.00**	**2.28**	**2.69**	**2.97**

Implied Market-based Inflationary Expectations

Qtr	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr
2003-Q1	1.58	1.65	1.85		
2003-Q2	1.42	1.52	1.68		
2003-Q3	1.78	1.87	2.03		
2003-Q4	2.01	2.13	2.28		
2004-Q1	2.17	2.26	2.31		
2004-Q2	2.47	2.50	2.55		
2004-Q3	2.34	2.37	2.41	2.79	
2004-Q4	2.56	2.55	2.48	2.79	
2005-Q1	2.72	2.68	2.58	2.83	
2005-Q2	2.57	2.55	2.48	2.72	
2005-Q3	2.44	2.41	2.39	2.52	
2005-Q4	2.47	2.44	2.45	2.64	
2006-Q1	2.55	2.50	2.48	2.69	
2006-Q2	2.65	2.62	2.61	2.80	
2006-Q3	2.47	2.48	2.52	2.71	
2006-Q4	2.20	2.24	2.31	2.54	
2007-Q1	2.36	2.32	2.35	2.54	
2007-Q2	2.41	2.39	2.41	2.58	
2007-Q3	2.13	2.16	2.28	2.55	
2007-Q4	2.24	2.17	2.34	2.54	
2008-Q1	2.17	2.13	2.34	2.59	
2008-Q2	2.37	2.29	2.40	2.56	
2008-Q3	1.93	1.96	2.16	2.33	
2008-Q4	-0.55	-0.29	0.65	1.24	
2009-Q1	0.39	0.69	0.95	1.35	
2009-Q2	1.11	1.51	1.60	1.88	
2009-Q3	1.30	1.72	1.77	2.06	
2009-Q4	1.72	2.04	2.09	2.29	
2010-Q1	1.96	2.22	2.28	2.49	2.47
2010-Q2	1.80	2.03	2.13	2.43	2.49
2010-Q3	1.35	1.63	1.73	1.92	2.09
2010-Q4	1.59	1.90	2.12	2.36	2.51
2011-Q1	2.05	2.16	2.37	2.61	2.56
2011-Q2	2.15	2.22	2.41	2.57	2.56
2011-Q3	1.81	2.00	2.15	2.39	2.45
2011-Q4	1.71	1.89	1.99	2.14	2.19
2012-Q1	1.92	2.04	2.20	2.29	2.36
2012-Q2	**1.86**	**1.99**	**2.17**	**2.21**	**2.28**
2012-Q3	1.94	2.09	2.28	2.35	2.31
2012-Q4	**2.11**	**2.27**	**2.47**	**2.48**	**2.50**
2013-Q1	2.23	2.31	2.54	2.55	2.58
2013-Q2	**1.95**	**2.01**	**2.25**	**2.32**	**2.34**
2013-Q3	1.82	1.95	2.15	2.29	2.29
2013-Q4	**1.73**	**1.86**	**2.17**	**2.31**	**2.29**
2014-Q1	1.77	1.85	2.18	2.30	2.29
2014-Q2	**1.90**	**1.92**	**2.20**	**2.30**	**1.71**
2014-Q3	1.83	1.92	2.18	2.28	2.29
2014-Q4	**1.41**	**1.61**	**1.83**	**1.95**	**2.02**

Structured Raw FED H.15 UST Data

FRB **H.15** Market Yield on U.S. Treasury (UST) Securities at Constant Maturity, Quoted on an Investment Basis in Percent per Year

Last Updated: 1-Apr-14 @ http://www.federalreserve.gov/releases/H15/data.htm

Staff Accessed , Feb. 5, 2015 at: http://federalreserve.gov/releases/h15/data.htm

Monthly

	Year		H.15 ID
TIPS-05m	5	Inflation Indexed	RIFLGFCY05_XII_N.M
TIPS-07m	7		RIFLGFCY07_XII_N.M
TIPS-10m	10		RIFLGFCY10_XII_N.M
TIPS-20m	20		RIFLGFCY20_XII_N.M
TIPS-30m	30		RIFLGFCY30_XII_N.M

Monthly

	Year	H.15 ID
UST-05m	5	RIFLGFCY05_N.M
UST-07m	7	RIFLGFCY07_N.M
UST-10m	10	RIFLGFCY10_N.M
UST-20m	20	RIFLGFCY20_N.M
UST-30m	30	RIFLGFCY30_N.M

Annual

	Year		H.15 ID
TIPS-05a	5	Inflation Indexed	RIFLGFCY05_XII_N.A
TIPS-07a	7		RIFLGFCY07_XII_N.A
TIPS-10a	10		RIFLGFCY10_XII_N.A
TIPS-20a	20		RIFLGFCY20_XII_N.A
TIPS-30a	30		RIFLGFCY30_XII_N.A

Annual

	Year	H.15 ID
UST-05a	5	RIFLGFCY05_N.A
UST-07a	7	RIFLGFCY07_N.A
UST-10a	10	RIFLGFCY10_N.A
UST-20a	20	RIFLGFCY20_N.A
UST-30a	30	RIFLGFCY30_N.A

Month	TIPS-05m	TIPS-07m	TIPS-10m	TIPS-20m	TIPS-30m	Month	UST-05m	UST-07m	UST-10m	UST-20m	UST-30m		
2003-01	1.65	2.10	2.29			2003-01	3.05	3.60	4.05	5.02			
2003-02	1.24	1.74	1.99			2003-02	2.90	3.45	3.90	4.87			
2003-03	1.09	1.60	1.94			2003-03	2.78	3.34	3.81	4.82			
2003-04	1.36	1.85	2.18			2003-04	2.93	3.47	3.96	4.91			
2003-05	1.18	1.61	1.91			2003-05	2.52	3.07	3.57	4.52			
2003-06	0.91	1.37	1.72			2003-06	2.27	2.84	3.33	4.34			
2003-07	1.30	1.76	2.11			2003-07	2.87	3.45	3.98	4.92			
2003-08	1.48	1.97	2.32			2003-08	3.37	3.96	4.45	5.39			
2003-09	1.29	1.80	2.19			2003-09	3.18	3.74	4.27	5.21			
2003-10	1.21	1.68	2.08			2003-10	3.19	3.75	4.29	5.21			
2003-11	1.27	1.64	1.96			2003-11	3.29	3.81	4.30	5.17			
2003-12	1.23	1.64	1.98			2003-12	3.27	3.79	4.27	5.11			
2004-01	1.09	1.48	1.89			2004-01	3.12	3.65	4.15	5.01			
2004-02	0.86	1.31	1.76			2004-02	3.07	3.59	4.08	4.94			
2004-03	0.52	0.98	1.47			2004-03	2.79	3.31	3.83	4.72			
2004-04	1.02	1.49	1.90			2004-04	3.39	3.89	4.35	5.16			
2004-05	1.34	1.77	2.09			2004-05	3.85	4.31	4.72	5.46			
2004-06	1.41	1.80	2.15	TIPS-20		2004-06	3.93	4.35	4.73	5.45			
2004-07	1.29	1.68	2.02	2.44		2004-07	3.69	4.11	4.50	5.24			
2004-08	1.12	1.51	1.86	2.23		2004-08	3.47	3.90	4.28	5.07			
2004-09	1.10	1.46	1.80	2.16		2004-09	3.36	3.75	4.13	4.89			
2004-10	0.97	1.35	1.73	2.13		2004-10	3.35	3.75	4.10	4.85			
2004-11	0.90	1.27	1.68	2.09		2004-11	3.53	3.88	4.19	4.89			
2004-12	0.92	1.28	1.67	2.02		2004-12	3.60	3.93	4.23	4.88			
2005-01	1.13	1.40	1.72	1.98		2005-01	3.71	3.97	4.22	4.77			
2005-02	1.08	1.33	1.63	1.85		2005-02	3.77	3.97	4.17	4.61			
2005-03	1.29	1.49	1.79	1.95		2005-03	4.17	4.33	4.50	4.89			
2005-04	1.23	1.42	1.71	1.87		2005-04	4.00	4.16	4.34	4.75			
2005-05	1.28	1.41	1.65	1.82		2005-05	3.85	3.94	4.14	4.56			
2005-06	1.39	1.49	1.67	1.80		2005-06	3.77	3.86	4.00	4.35			
2005-07	1.67	1.75	1.88	2.00		2005-07	3.98	4.06	4.18	4.48			
2005-08	1.71	1.79	1.89	2.02		2005-08	4.12	4.18	4.26	4.53			
2005-09	1.40	1.56	1.70	1.93		2005-09	4.01	4.08	4.20	4.51			
2005-10	1.70	1.82	1.94	2.09		2005-10	4.33	4.38	4.46	4.74			
2005-11	1.97	2.03	2.06	2.16		2005-11	4.45	4.48	4.54	4.83			
2005-12	2.09	2.10	2.12	2.14		2005-12	4.39	4.41	4.47	4.73			
2006-01	1.93	1.98	2.01	2.05		2006-01	4.35	4.37	4.42	4.65	UST-30		
2006-02	1.98	2.02	2.05	2.01		2006-02	4.57	4.56	4.57	4.73	4.54		
2006-03	2.09	2.15	2.20	2.17		2006-03	4.72	4.71	4.72	4.91	4.73		
2006-04	2.26	2.34	2.41	2.43		2006-04	4.90	4.94	4.99	5.22	5.06		
2006-05	2.30	2.36	2.45	2.48		2006-05	5.00	5.03	5.11	5.35	5.20		
2006-06	2.45	2.48	2.53	2.54		2006-06	5.07	5.08	5.11	5.29	5.15		
2006-07	2.46	2.48	2.51	2.52		2006-07	5.04	5.05	5.09	5.25	5.13		
2006-08	2.27	2.29	2.29	2.31		2006-08	4.82	4.83	4.88	5.08	5.00		
2006-09	2.38	2.35	2.32	2.31		2006-09	4.67	4.68	4.72	4.93	4.85		
2006-10	2.51	2.45	2.41	2.38		2006-10	4.69	4.69	4.73	4.94	4.85		
2006-11	2.41	2.35	2.29	2.23		2006-11	4.58	4.58	4.60	4.78	4.69		
2006-12	2.28	2.28	2.25	2.26		2006-12	4.53	4.54	4.56	4.78	4.68		
2007-01	2.47	2.47	2.44	2.42		2007-01	4.75	4.75	4.76	4.95	4.85		
2007-02	2.34	2.38	2.36	2.38		2007-02	4.71	4.71	4.72	4.93	4.82		
2007-03	2.04	2.14	2.18	2.27		2007-03	4.48	4.50	4.56	4.81	4.72		
2007-04	2.12	2.20	2.26	2.35		2007-04	4.59	4.62	4.69	4.95	4.87		
2007-05	2.29	2.32	2.37	2.45		2007-05	4.67	4.69	4.75	4.98	4.90		
2007-06	2.65	2.67	2.69	2.67		2007-06	5.03	5.05	5.10	5.29	5.20		
2007-07	2.60	2.63	2.64	2.62		2007-07	4.88	4.93	5.00	5.19	5.11		
2007-08	2.39	2.45	2.44	2.47		2007-08	4.43	4.53	4.67	5.00	4.93		
2007-09	2.14	2.24	2.26	2.30		2007-09	4.20	4.33	4.52	4.84	4.79		
2007-10	2.01	2.15	2.20	2.26		2007-10	4.20	4.33	4.53	4.83	4.77		
2007-11	1.35	1.65	1.77	1.99		2007-11	3.67	3.87	4.15	4.56	4.52		
2007-12	1.27	1.62	1.79	2.08		2007-12	3.49	3.74	4.10	4.57	4.53		
2008-01	0.86	1.24	1.47	1.81		2008-01	2.98	3.31	3.74	4.35	4.33		
2008-02	0.65	1.09	1.41	1.87		2008-02	2.78	3.21	3.74	4.49	4.52		
2008-03	0.23	0.73	1.09	1.76		2008-03	2.48	2.93	3.51	4.36	4.39		
2008-04	0.62	1.00	1.36	1.91		2008-04	2.84	3.19	3.68	4.44	4.44		
2008-05	0.79	1.16	1.46	2.00		2008-05	3.15	3.46	3.88	4.60	4.60		
2008-06	0.97	1.35	1.63	2.19		2008-06	3.49	3.73	4.10	4.74	4.69		
2008-07	0.84	1.24	1.57	2.09		2008-07	3.30	3.60	4.01	4.62	4.57		
2008-08	1.15	1.47	1.68	2.15		2008-08	3.14	3.46	3.89	4.53	4.50		
2008-09	1.55	1.71	1.85	2.25		2008-09	2.88	3.25	3.69	4.32	4.27		
2008-10	2.75	2.96	2.75	2.87		2008-10	2.73	3.19	3.81	4.45	4.17		
2008-11	3.69	3.84	2.89	3.00		2008-11	2.29	2.82	3.53	4.27	4.00		
2008-12	1.76	1.96	2.17	2.32		2008-12	1.52	1.89	2.42	3.18	2.87		
2009-01	1.59	1.72	1.91	2.46		2009-01	1.60	1.98	2.52	3.46	3.13		
2009-02	1.29	1.48	1.75	2.31		2009-02	1.87	2.30	2.87	3.83	3.59		
2009-03	1.23	1.43	1.71	2.26		2009-03	1.82	2.42	2.82	3.78	3.64		
2009-04	1.11	1.29	1.57	2.22		2009-04	1.86	2.47	2.93	3.84	3.76		
2009-05	1.07	1.34	1.72	2.36		2009-05	2.13	2.81	3.29	4.22	4.23		
2009-06	1.18	1.48	1.86	2.36		2009-06	2.71	3.37	3.72	4.51	4.52		
2009-07	1.18	1.44	1.82	2.31		2009-07	2.46	3.14	3.56	4.38	4.41		
2009-08	1.29	1.49	1.77	2.22		2009-08	2.57	3.21	3.59	4.33	4.37		
2009-09	1.03	1.29	1.64	2.13		2009-09	2.37	3.02	3.40	4.14	4.19		
2009-10	0.83	1.12	1.48	2.04		2009-10	2.33	2.96	3.39	4.16	4.19		
2009-11	0.48	0.84	1.28	1.90		2009-11	2.23	2.92	3.40	4.24	4.31		
2009-12	0.43	0.86	1.36	1.99		2009-12	2.34	3.07	3.59	4.40	4.49		
2010-01	0.42	0.85	1.37	2.00	TIPS-30	2010-01	2.48	3.21	3.73	4.50	4.60		
2010-02	0.42	0.90	1.42	2.03	2.16	2010-02	2.36	3.12	3.69	4.48	4.62		
2010-03	0.56	1.08	1.51	1.98	2.15	2010-03	2.43	3.16	3.73	4.49	4.64		
2010-04	0.62	1.10	1.50	1.90	2.05	2010-04	2.58	3.28	3.85	4.53	4.69		
2010-05	0.41	0.86	1.31	1.72	1.83	2010-05	2.18	2.86	3.42	4.11	4.29		
2010-06	0.34	0.76	1.26	1.69	1.77	2010-06	2.00	2.66	3.20	3.95	4.13		
2010-07	0.34	0.73	1.24	1.80	1.87	2010-07	1.76	2.43	3.01	3.80	3.99		
2010-08	0.13	0.51	1.02	1.65	1.76	2010-08	1.47	2.10	2.70	3.52	3.80		
2010-09	0.13	0.46	0.91	1.58	1.66	2010-09	1.41	2.05	2.65	3.47	3.77		
2010-10	-0.32	0.02	0.53	1.32	1.44	2010-10	1.18	1.85	2.54	3.52	3.87		
2010-11	-0.21	0.17	0.67	1.44	1.61	2010-11	1.35	2.02	2.76	3.82	4.19		
2010-12	0.21	0.65	1.04	1.67	1.89	2010-12	1.93	2.66	3.29	4.17	4.42		
2011-01	0.06	0.62	1.06	1.70	1.97	2011-01	1.99	2.72	3.39	4.28	4.52		
2011-02	0.25	0.84	1.24	1.85	2.13	2011-02	2.26	2.96	3.58	4.42	4.65		
2011-03	-0.09	0.54	0.96	1.58	1.89	2011-03	2.11	2.80	3.41	4.27	4.51		
2011-04	-0.14	0.49	0.86	1.48	1.79	2011-04	2.17	2.84	3.46	4.28	4.50		
2011-05	-0.34	0.29	0.78	1.47	1.77	2011-05	1.84	2.51	3.17	4.01	4.29		
2011-06	-0.38	0.21	0.76	1.53	1.78	2011-06	1.58	2.29	3.00	3.91	4.23		
2011-07	-0.49	0.09	0.62	1.36	1.62	2011-07	1.54	2.28	3.00	3.95	4.27		
2011-08	-0.75	-0.36	0.14	0.81	1.10	2011-08	1.02	1.63	2.30	3.24	3.65		
2011-09	-0.72	-0.39	0.08	0.69	1.02	2011-09	0.90	1.42	1.98	2.83	3.18		
2011-10	-0.63	-0.28	0.19	0.72	0.99	2011-10	1.06	1.62	2.15	2.87	3.13		
2011-11	-0.85	-0.46	0.00	0.55	0.78	2011-11	0.91	1.45	2.01	2.72	3.02		
2011-12	-0.78	-0.44	-0.03	0.56	0.78	2011-12	0.89	1.43	1.98	2.67	2.98		
2012-01	-0.92	-0.55	-0.11	0.51	0.74	2012-01	0.84	1.38	1.97	2.70	3.03		
2012-02	-1.11	-0.69	-0.25	0.45	0.72	2012-02	0.83	1.37	1.97	2.75	3.11		
2012-03	-1.03	-0.57	-0.14	0.56	0.87	2012-03	1.02	1.56	2.17	2.94	3.28		
2012-04	**-1.06**	**-0.65**	**-0.21**	**0.50**	**0.79**	**2012-04**	**0.89**	**1.43**	**2.05**	**2.82**	**3.18**		
2012-05	**-1.12**	**-0.79**	**-0.34**	**0.44**	**0.68**	**2012-05**	**0.76**	**1.21**	**1.80**	**2.53**	**2.93**	**NWN**	**UG 221**
2012-06	**-1.05**	**-0.82**	**-0.50**	**0.10**	**0.50**	**2012-06**	**0.71**	**1.08**	**1.62**	**2.31**	**2.70**		
2012-07	-1.15	-0.92	-0.60	-0.01	0.39	2012-07	0.62	0.98	1.53	2.22	2.59		
2012-08	-1.19	-0.94	-0.59	0.06	0.47	2012-08	0.71	1.14	1.68	2.40	2.77		
2012-09	-1.47	-1.17	-0.71	0.02	0.44	2012-09	0.67	1.12	1.72	2.49	2.88		
2012-10	**-1.47**	**-1.18**	**-0.75**	**-0.01**	**0.41**	**2012-10**	**0.71**	**1.15**	**1.75**	**2.51**	**2.90**	**PGE**	**UE 262**
2012-11	**-1.38**	**-1.13**	**-0.77**	**-0.06**	**0.35**	**2012-11**	**0.67**	**1.08**	**1.65**	**2.39**	**2.80**	**&**	
2012-12	**-1.40**	**-1.13**	**-0.76**	**0.00**	**0.33**	**2012-12**	**0.70**	**1.13**	**1.72**	**2.47**	**2.88**	**PAC**	**UE 263**
2013-01	-1.39	-1.04	-0.61	0.20	0.48	2013-01	0.81	1.30	1.91	2.68	3.08		
2013-02	-1.39	-0.94	-0.57	0.19	0.57	2013-02	0.85	1.35	1.98	2.78	3.17		
2013-03	-1.43	-0.97	-0.59	0.19	0.62	2013-03	0.82	1.32	1.96	2.78	3.16		
2013-04	**-1.38**	**-0.97**	**-0.65**	**0.07**	**0.48**	**2013-04**	**0.71**	**1.15**	**1.76**	**2.55**	**2.93**		
2013-05	**-1.14**	**-0.69**	**-0.36**	**0.35**	**0.72**	**2013-05**	**0.84**	**1.31**	**1.93**	**2.73**	**3.11**		
2013-06	**-0.59**	**-0.21**	**0.25**	**0.98**	**1.21**	**2013-06**	**1.20**	**1.71**	**2.30**	**3.07**	**3.40**		
2013-07	-0.45	0.02	0.46	1.09	1.34	2013-07	1.40	1.99	2.58	3.31	3.61		
2013-08	-0.33	0.15	0.55	1.16	1.44	2013-08	1.52	2.15	2.74	3.49	3.76	**AVA**	**UG 246**
2013-09	-0.17	0.34	0.66	1.22	1.50	2013-09	1.60	2.22	2.81	3.53	3.79		
2013-10	**-0.41**	**0.11**	**0.43**	**1.05**	**1.37**	**2013-10**	**1.37**	**1.99**	**2.62**	**3.38**	**3.68**		
2013-11	**-0.38**	**0.18**	**0.55**	**1.20**	**1.51**	**2013-11**	**1.37**	**2.07**	**2.72**	**3.50**	**3.80**	**PGE**	**UE 283**
2013-12	**-0.09**	**0.47**	**0.74**	**1.32**	**1.61**	**2013-12**	**1.58**	**2.29**	**2.90**	**3.63**	**3.89**		
2014-01	-0.09	0.45	0.63	1.17	1.44	2014-01	1.65	2.29	2.86	3.52	3.77		
2014-02	-0.26	0.30	0.55	1.12	1.40	2014-02	1.52	2.15	2.71	3.38	3.66		
2014-03	-0.14	0.37	0.56	1.05	1.33	2014-03	1.64	2.23	2.72	3.35	3.62		
2014-04	**-0.11**	**0.38**	**0.54**	**0.98**	**1.23**	**2014-04**	**1.70**	**2.27**	**2.71**	**3.27**	**3.52**		
2014-05	**-0.34**	**0.21**	**0.37**	**0.82**	**1.08**	**2014-05**	**1.59**	**2.12**	**2.56**	**3.12**	**3.39**		
2014-06	**-0.29**	**0.23**	**0.37**	**0.84**	**1.11**	**2014-06**	**1.68**	**2.19**	**2.60**	**3.15**	**3.42**		
2014-07	-0.27	0.18	0.28	0.72	0.98	2014-07	1.70	2.17	2.54	3.07	3.33		
2014-08	-0.21	0.15	0.22	0.64	0.90	2014-08	1.63	2.08	2.42	2.94	3.20		
2014-09	0.10	0.38	0.46	0.81	1.05	2014-09	1.77	2.22	2.53	3.01	3.26		
2014-10	**0.06**	**0.32**	**0.38**	**0.74**	**0.96**	**2014-10**	**1.55**	**1.98**	**2.30**	**2.77**	**3.04**		
2014-11	**0.14**	**0.37**	**0.45**	**0.77**	**0.99**	**2014-11**	**1.62**	**2.03**	**2.33**	**2.76**	**3.04**	**PGE**	**UE 294**
2014-12	**0.37**	**0.47**	**0.51**	**0.73**	**0.89**	**2014-12**	**1.64**	**1.98**	**2.21**	**2.55**	**2.83**		

Year	TIPS-05a	TIPS-07a	TIPS-10a	TIPS-20a	TIPS-30a
2003	1.27	1.73	2.06		
2004	1.04	1.45	1.83	2.14	
2005	1.50	1.63	1.81	1.97	
2006	2.28	2.29	2.31	2.31	
2007	2.15	2.25	2.29	2.36	
2008	1.30	1.63	1.77	2.18	
2009	1.06	1.32	1.66	2.21	
2010	0.26	0.68	1.15	1.73	1.82
2011	-0.41	0.09	0.55	1.19	1.47
2012	-1.19	-0.87	-0.48	0.22	0.56
2013	0.76	-0.29	0.07	0.75	1.07
2014	**-0.09**	**0.32**	**0.44**	**0.86**	**1.11**

Year	UST-05a	UST-07a	UST-10a	UST-20a	UST-30a
2003	2.97	3.52	4.01	4.96	
2004	3.43	3.87	4.27	5.04	
2005	4.05	4.15	4.29	4.64	
2006	4.75	4.76	4.80	5.00	4.91
2007	4.43	4.51	4.63	4.91	4.84
2008	2.80	3.17	3.66	4.36	4.28
2009	2.20	2.82	3.26	4.11	4.08
2010	1.93	2.62	3.22	4.03	4.25
2011	1.52	2.16	2.78	3.62	3.91
2012	0.76	1.22	1.80	2.54	2.92
2013	1.17	1.74	2.35	3.12	3.45
2014	**1.64**	**2.14**	**2.54**	**3.07**	**3.34**

CASE: UE 294
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 205

Staff Historical GDP Analysis with BEA Data

Exhibits in Support
of Opening Testimony

June 15, 2015

Staff Trend Analysis of Historical U.S. BEA GDP Data

Bureau of Economic Analysis (BEA) — **Staff Accessed 1/30/15**

Current-Dollar and "Real" Gross Domestic Product (GDP)

Annual — http://www.bea.gov/national/index.htm

Quarterly — (Seasonally adjusted annual rates)

1980 through 2014 Q4 — Average 5.37% Nominal

Yr	GDP in billions of current dollars	GDP in billions of chained 2009 dollars	Quarter	GDP in billions of current dollars	GDP in billions of chained 2009 dollars	Qtr#	Average	2.74%	Real
1929	104.6	1,056.6	1947q1	243.1	1,934.5	1	1	8.783381	1980
1930	92.2	966.7	1947q2	246.3	1,932.3	2	2	8.762896	
1931	77.4	904.8	1947q3	250.1	1,930.3	3	3	8.761378	
1932	59.5	788.2	1947q4	260.3	1,960.7	4	4	8.779742	
1933	57.2	778.3	1948q1	266.2	1,989.5	5	5	8.800219	1981
1934	66.8	862.2	1948q2	272.9	2,021.9	6	6	8.792899	
1935	74.3	939.0	1948q3	279.5	2,033.2	7	7	8.804310	
1936	84.9	1,060.5	1948q4	280.7	2,035.3	8	8	8.792565	
1937	93.0	1,114.6	1949q1	275.4	2,007.5	9	9	8.775704	1982
1938	87.4	1,077.7	1949q2	271.7	2,000.8	10	10	8.781125	
1939	93.5	1,163.6	1949q3	273.3	2,022.8	11	11	8.777525	
1940	102.9	1,266.1	1949q4	271.0	2,004.7	12	12	8.778495	
1941	129.4	1,490.3	1950q1	281.2	2,084.6	13	13	8.791516	1983
1942	166.0	1,771.8	1950q2	290.7	2,147.6	14	14	8.814078	
1943	203.1	2,073.7	1950q3	308.5	2,230.4	15	15	8.833463	
1944	224.6	2,239.4	1950q4	320.3	2,273.4	16	16	8.853880	
1945	228.2	2,217.8	1951q1	336.4	2,304.5	17	17	8.873552	1984
1946	227.8	1,960.9	1951q2	344.5	2,344.5	18	18	8.890961	
1947	249.9	1,939.4	1951q3	351.8	2,392.8	19	19	8.900753	
1948	274.8	2,020.0	1951q4	356.6	2,398.1	20	20	8.908695	
1949	272.8	2,008.9	1952q1	360.2	2,423.5	21	21	8.918583	1985
1950	300.2	2,184.0	1952q2	361.4	2,428.5	22	22	8.927699	
1951	347.3	2,360.0	1952q3	368.1	2,446.1	23	23	8.943140	
1952	367.7	2,456.1	1952q4	381.2	2,526.4	24	24	8.950611	
1953	389.7	2,571.4	1953q1	388.5	2,573.4	25	25	8.959838	1986
1954	391.1	2,556.9	1953q2	392.3	2,593.5	26	26	8.964414	
1955	426.2	2,739.0	1953q3	391.7	2,578.9	27	27	8.974441	
1956	450.1	2,797.4	1953q4	386.5	2,539.8	28	28	8.979606	
1957	474.9	2,856.3	1954q1	385.9	2,528.0	29	29	8.986572	1987
1958	482.0	2,835.3	1954q2	386.7	2,530.7	30	30	8.997729	
1959	522.5	3,031.0	1954q3	391.6	2,559.4	31	31	9.006754	
1960	543.3	3,108.7	1954q4	400.3	2,609.3	32	32	9.023131	
1961	563.3	3,188.1	1955q1	413.8	2,683.8	33	33	9.028735	1988
1962	605.1	3,383.1	1955q2	422.2	2,727.5	34	34	9.041863	
1963	638.6	3,530.4	1955q3	430.9	2,764.1	35	35	9.047621	
1964	685.8	3,734.0	1955q4	437.8	2,780.8	36	36	9.060784	
1965	743.7	3,976.7	1956q1	440.5	2,770.0	37	37	9.070814	1989
1966	815.0	4,238.9	1956q2	446.8	2,792.9	38	38	9.078647	
1967	861.7	4,355.2	1956q3	452.0	2,790.6	39	39	9.086080	
1968	942.5	4,569.0	1956q4	461.3	2,836.2	40	40	9.088195	
1969	1,019.9	4,712.5	1957q1	470.6	2,854.5	41	41	9.099085	1990
1970	1,075.9	4,722.0	1957q2	472.8	2,848.2	42	42	9.102944	
1971	1,167.8	4,877.6	1957q3	480.3	2,875.9	43	43	9.103189	
1972	1,282.4	5,134.3	1957q4	475.7	2,846.4	44	44	9.094638	
1973	1,428.5	5,424.1	1958q1	468.4	2,772.7	45	45	9.089934	1991
1974	1,548.8	5,396.0	1958q2	472.8	2,790.9	46	46	9.097664	
1975	1,688.9	5,385.4	1958q3	486.7	2,855.5	47	47	9.102454	
1976	1,877.6	5,675.4	1958q4	500.4	2,922.3	48	48	9.106800	
1977	2,086.0	5,937.0	1959q1	511.1	2,976.6	49	49	9.118554	1992
1978	2,356.6	6,267.2	1959q2	524.2	3,049.0	50	50	9.129510	
1979	2,632.1	6,466.2	1959q3	525.2	3,043.1	51	51	9.139188	
1980	2,862.5	6,450.4	1959q4	529.3	3,055.1	52	52	9.149156	

OLS Regression

Annualized Real LN GPD Q

2.87%

Regression Statistics	
Multiple R	0.988570992
R Square	0.977272606
Adjusted R	0.977107915
Standard E	0.044086238
Observatio	140

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regressior	1	11.53323798	11.53323798	5933.9676	2.7419E-115
Residual	138	0.2682163	0.001943596		
Total	139	11.80145428			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	8.781241805	0.007492035	1172.077033	9.2E-278	8.766427778	8.796055831	8.766427778	8.796055831
X Variable	**0.007102075**	9.21961E-05	77.03225051	2.74E-115	0.006919776	0.007284375	0.006919776	0.007284375

GDP is an array of expenditure and income data collected by BEA directly and through other government agencies.

Note — **July 31, 2013, 14th Comprehensive Significant Revision:**
BEA revised its tables back to 1929 in to order to count:
1. **Artistic Works**
2. **Research and Development**

as Capital Investments that Depreciate Over Time
rather than one time expenditures

From an Economy based on
(Industry and Manufacturing)
to one based on
(Knowledge and Information)

This comprehensive revision did not cause a large percentage jump.
The relative difference of actual amounts over time changed little.

Staff intentionally truncates data feed and transformation. – See Staff work papers for full data feed.

CASE: UE 294
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 206

Representative GDP Growth Projections

Exhibits in Support of Opening Testimony

June 15, 2015

The President's 2016 Fiscal Year Budget – Chapter 5 – Summary Tables

Table S-12 Economic Assumptions – https://medium.com/budget-document:

Table S–12. Economic Assumptions[1]

(Calendar years)

	Actual 2013	Projections 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Gross Domestic Product (GDP):													
Nominal level, billions of dollars	16,768	17,394	18,188	19,039	19,933	20,847	21,770	22,717	23,705	24,736	25,812	26,934	28,106
Percent change, nominal GDP, year/year	3.7	3.7	4.6	4.7	4.7	4.6	4.4	4.3	4.3	4.3	4.3	4.3	4.3
Real GDP, percent change, year/year	2.2	2.2	3.1	3.0	2.8	2.6	2.4	2.3	2.3	2.3	2.3	2.3	2.3
Real GDP, percent change, Q4/Q4	3.1	2.1	3.0	3.0	2.7	2.5	2.3	2.3	2.3	2.3	2.3	2.3	2.3
GDP chained price index, percent change, year/year	1.5	1.5	1.4	1.6	1.8	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Consumer Price Index,[2] percent change, year/year	1.5	1.7	1.4	1.9	2.1	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Interest rates, percent:[3]													
91-day Treasury bills[4]	0.1	*	0.4	1.5	2.4	2.9	3.2	3.3	3.4	3.4	3.5	3.5	3.5
10-year Treasury notes	2.4	2.6	2.8	3.3	3.7	4.0	4.3	4.5	4.5	4.5	4.5	4.5	4.5
Unemployment rate, civilian, percent[3]	7.4	6.2	5.4	5.1	4.9	4.9	5.0	5.1	5.2	5.2	5.2	5.2	5.2

*0.05 percent or less.

Note: A more detailed table of economic assumptions appears in Chapter 2, "Economic Assumptions and Interactions with the Budget," in the *Analytical Perspectives* volume of the Budget.

[1] Based on information available as of mid-November 2014.

[2] Seasonally adjusted CPI for all urban consumers.

[3] Annual average.

[4] Average rate, secondary market (bank discount basis).

Chapter 6 – OMB Contributors To The 2016 Budget

CASE: UE 294
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 207

Cost of Long-Term Debt

Exhibits in Support
Of Opening Testimony

<u>REDACTED</u>
June 15, 2015

This page is confidential.

You must have signed the Protective Order No: 15-036

in Docket No. UE 294 to view this page.

CASE: UE 294
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 208

PGE Depiction of Rate Base Expansion to Investors

Exhibits in Support of Opening Testimony

June 15, 2015

Portland General Electric

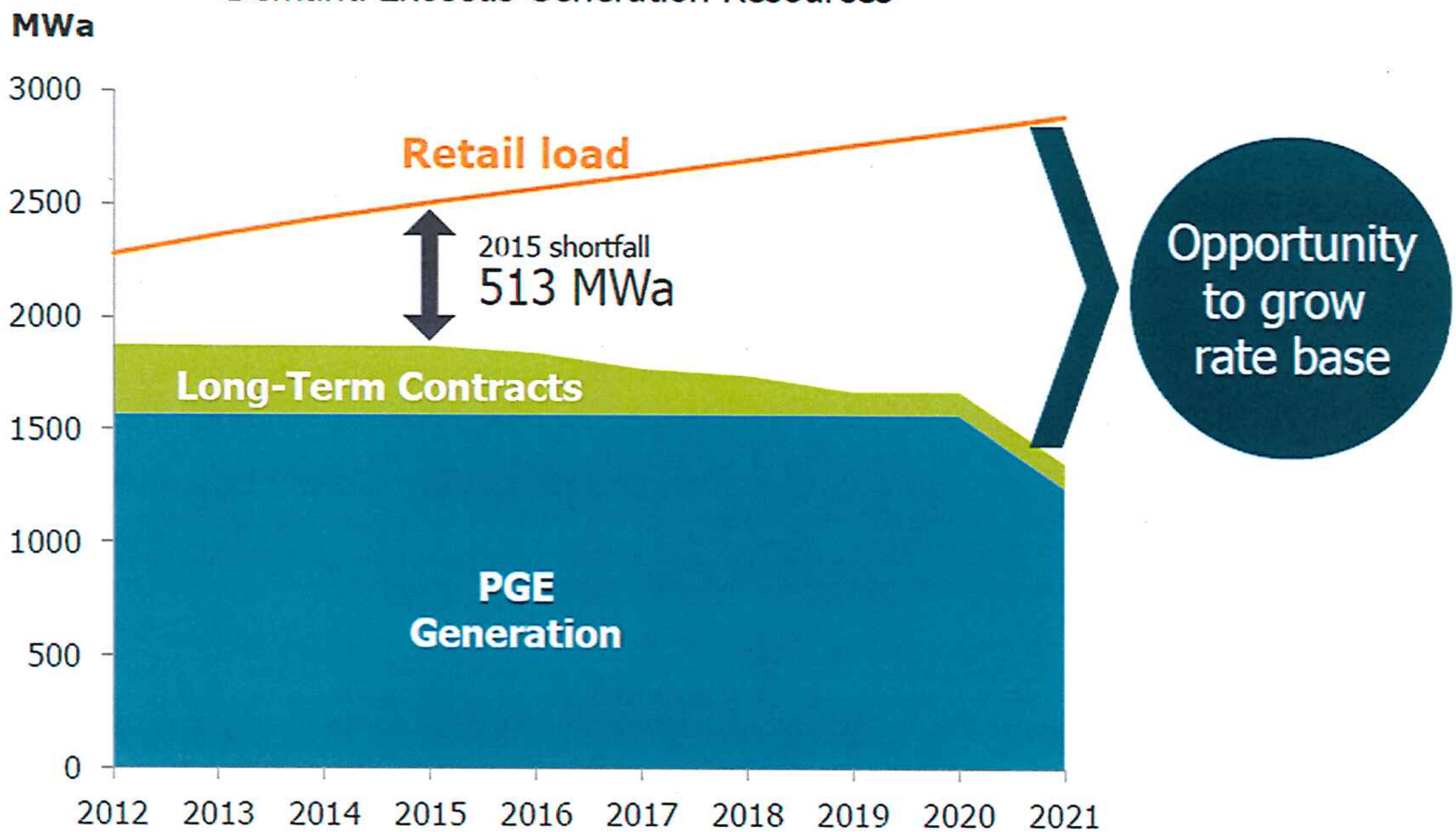
Investor Presentation

August 2012

Future Generation Need

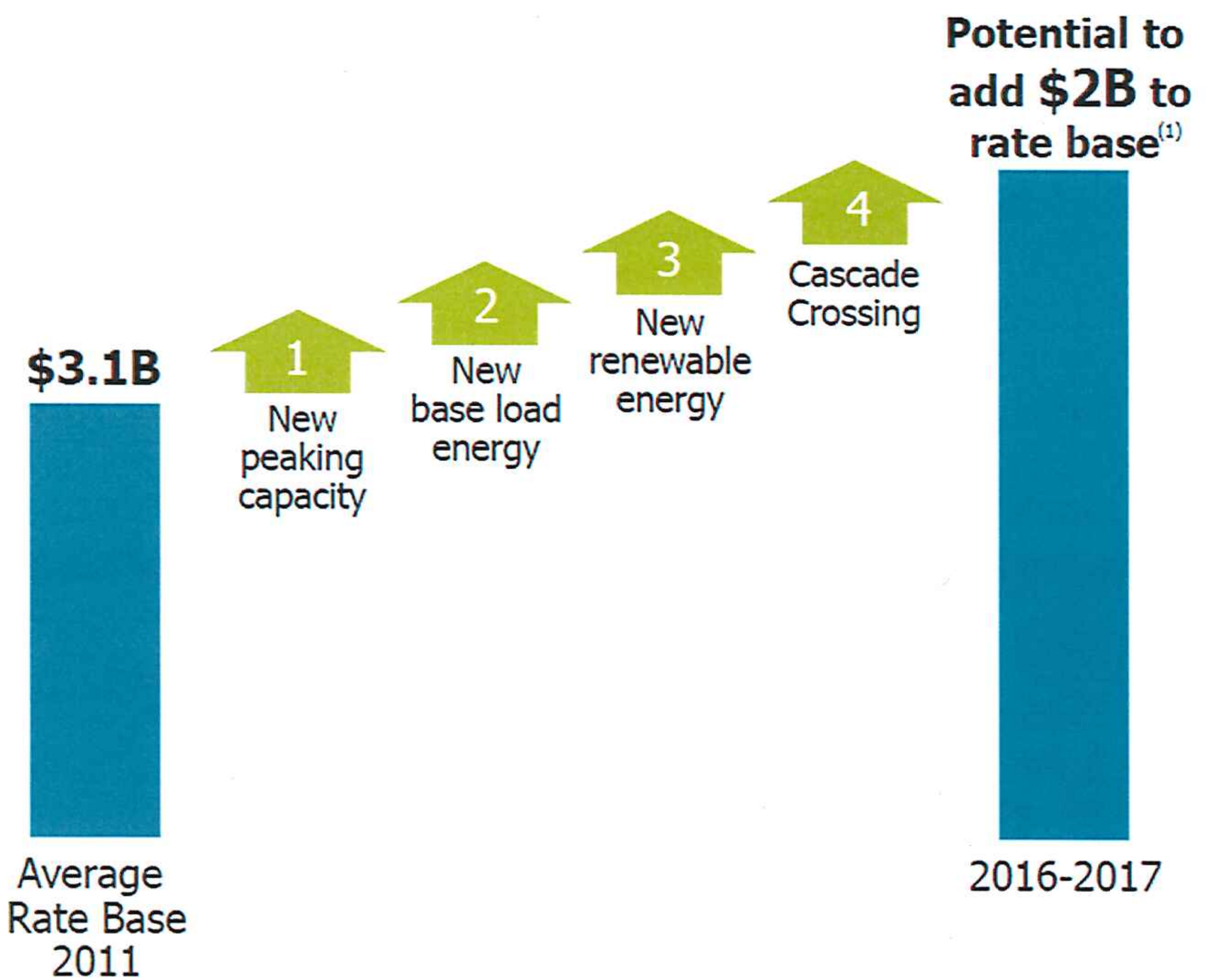
Load-Resource Forecast[1] - Energy

Demand Exceeds Generation Resources



1) Load-Resource Forecast Data from 2011 IRP Update, filed with the OPUC on 11/23/2011; shortfall is net of energy efficiency

Potential Opportunities for Rate Base Growth



1) Rate base growth dependent on outcome of RFP processes; PGE is committed to move forward with the least cost, least risk option for customers

CASE: UE 294
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 209

Value Line (VL) Electric Utility Profiles

Exhibits in Support of Opening Testimony

June 15, 2015

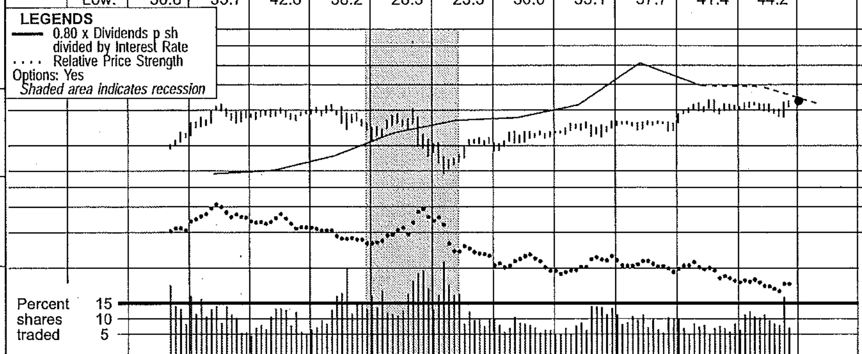
ALLETE NYSE-ALE

RECENT PRICE	53.22	P/E RATIO	17.4 (Trailing: 17.8; Median: NMF)	RELATIVE P/E RATIO	0.94	DIV'D YLD	3.8%	VALUE LINE

TIMELINESS 3 Lowered 9/19/14
SAFETY 2 New 10/1/04
TECHNICAL 4 Lowered 12/12/14
BETA .80 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
High:	37.5	51.7	49.3	51.3	49.0	35.3	37.9	42.5	42.7	54.1	53.3
Low:	30.8	35.7	42.6	38.2	28.3	23.3	30.0	35.1	37.7	41.4	44.2

LEGENDS
— 0.80 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range
2017 | 2018 | 2019
120 – 100 – 80 – 64 – 48 – 32 – 24 – 20 – 16 – 12 – 8

2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+15%)	7%
Low	45	(-15%)	1%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	1
to Sell	0	0	0	0	0	0	0	1	1

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	92	98	104
to Sell	66	75	75
Hld's(000)	29252	29801	29758

Percent shares traded 15 / 10 / 5

% TOT. RETURN 11/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.6	8.0
3 yr.	44.7	72.4
5 yr.	89.9	119.8

ALLETE, in its current configuration, began trading on September 21, 2004, the day after it spun off its automotive services business, ADESA (now KAR Auction Services, NYSE: KAR), to shareholders and effected a 1-for-3 reverse stock split. ALLETE shareholders received one share of ADESA for each ALLETE share held. Data for the "old" ALLETE are not shown because they are not comparable.

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
25.30	24.50	25.23	27.33	24.57	21.57	25.34	24.75	24.40	24.60	*25.25*	*25.30*	Revenues per sh	*28.25*
2.97	3.85	4.14	4.42	4.23	3.57	4.35	4.91	5.01	5.35	*5.65*	*6.10*	"Cash Flow" per sh	*7.25*
1.35	2.48	2.77	3.08	2.82	1.89	2.19	2.65	2.58	2.63	*2.85*	*3.20*	Earnings per sh A	*3.75*
.30	1.25	1.45	1.64	1.72	1.76	1.76	1.78	1.84	1.90	*1.96*	*2.04*	Div'd Decl'd per sh B ■ †	*2.30*
2.12	1.95	3.37	6.82	9.24	9.05	6.95	6.38	10.30	7.93	*14.05*	*6.65*	Cap'l Spending per sh	*5.50*
21.23	20.03	21.90	24.11	25.37	26.41	27.26	28.78	30.48	32.44	*34.70*	*36.60*	Book Value per sh C	*40.50*
29.70	30.10	30.40	30.80	32.60	35.20	35.80	37.50	39.40	41.40	*45.50*	*48.00*	Common Shs Outst'g D	*49.50*
25.2	17.9	16.5	14.8	13.9	16.1	16.0	14.7	15.9	18.6	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*13.5*
1.33	.95	.89	.79	.84	1.07	1.02	.92	1.01	1.05			Relative P/E Ratio	*.85*
.9%	2.8%	3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	4.5%	3.9%			Avg Ann'l Div'd Yield	*4.5%*
751.4	737.4	767.1	841.7	801.0	759.1	907.0	928.2	961.2	1018.4	*1150*	*1215*	Revenues ($mill)	*1400*
38.5	68.0	77.3	87.6	82.5	61.0	75.3	93.8	97.1	104.7	*120*	*150*	Net Profit ($mill)	*180*
38.8%	28.4%	37.5%	34.8%	34.3%	33.7%	37.2%	27.6%	28.1%	21.5%	*22.0%*	*15.0%*	Income Tax Rate	*15.0%*
1.8%	.4%	1.4%	6.6%	5.8%	12.8%	8.9%	2.7%	5.3%	4.4%	*7.0%*	*3.0%*	AFUDC % to Net Profit	*2.0%*
38.2%	39.1%	35.1%	35.6%	41.6%	42.8%	44.2%	44.3%	43.7%	44.6%	*46.0%*	*45.5%*	Long-Term Debt Ratio	*42.0%*
61.8%	60.9%	64.9%	64.4%	58.4%	57.2%	55.8%	55.7%	56.3%	55.4%	*54.0%*	*54.5%*	Common Equity Ratio	*58.0%*
1020.7	990.6	1025.6	1153.5	1415.4	1625.3	1747.6	1937.2	2134.6	2425.9	*2935*	*3210*	Total Capital ($mill)	*3475*
883.1	860.4	921.6	1104.5	1387.3	1622.7	1805.6	1982.7	2347.6	2576.5	*3080*	*3255*	Net Plant ($mill)	*3475*
5.1%	8.0%	8.6%	8.6%	6.7%	4.8%	5.4%	6.0%	5.6%	5.3%	*5.0%*	*5.5%*	Return on Total Cap'l	*6.0%*
6.1%	11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	*7.5%*	*8.5%*	Return on Shr. Equity	*9.0%*
6.1%	11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	*7.5%*	*8.5%*	Return on Com Equity E	*9.0%*
4.7%	5.2%	5.0%	5.8%	3.9%	.5%	1.5%	2.9%	2.3%	2.2%	*2.5%*	*3.0%*	Retained to Com Eq	*3.5%*
23%	54%	57%	51%	61%	93%	81%	66%	71%	72%	*70%*	*65%*	All Div'ds to Net Prof	*63%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $1377.2 mill. **Due in 5 Yrs** $246.0 mill.
LT Debt $1289.2 mill. **LT Interest** $57.7 mill.
(LT interest earned: 3.8x)
Leases, Uncapitalized Annual rentals $12.1 mill.

Pension Assets-12/13 $501.6 mill. **Oblig.** $622.8 mill.

Pfd Stock None

Common Stock 44,499,229 shs.

MARKET CAP: $2.4 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+5.6	+1.1	-1.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.30	5.24	5.45
Capacity at Peak (Mw)	1789	1790	1793
Peak Load, Winter (Mw) F	1599	1633	1646
Annual Load Factor (%)	79.0	79.0	NA
% Change Customers (avg)	+.5	+.5	NA
Fixed Charge Cov. (%)	344	341	306

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	--	-1.0%	*2.5%*
"Cash Flow"	--	3.5%	*6.0%*
Earnings	--	-2.0%	*6.0%*
Dividends	--	3.0%	*4.0%*
Book Value	--	5.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	242.2	219.9	226.9	239.2	928.2
2012	240.0	216.4	248.8	256.0	961.2
2013	263.8	235.6	251.0	268.0	1018.4
2014	296.5	260.7	288.9	*303.9*	*1150*
2015	*300*	*290*	*305*	*320*	*1215*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	1.07	.48	.57	.53	2.65
2012	.66	.39	.78	.75	2.58
2013	.83	.35	.63	.82	2.63
2014	.80	.40	.97	*.68*	*2.85*
2015	*.95*	*.45*	*.85*	*.95*	*3.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.44	.44	.44	.44	1.76
2011	.445	.445	.445	.445	1.78
2012	.46	.46	.46	.46	1.84
2013	.475	.475	.475	.475	1.90
2014	.49	.49	.49	.49	

BUSINESS: ALLETE, Inc. is the parent of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric rev. breakdown: taconite mining/processing, 27%; paper/wood products, 9%; other industrial, 7%; residential, 12%; commercial, 13%; wholesale, 10% other, 22%. ALLETE Clean Energy owns renewable energy projects. Has real estate operation in FL. Spun off automotive remarketing operation in '04. Generating sources: coal & lignite, 63%; wind, 6%; hydro, 1%; biomass, 1%; purch., 29%. '13 deprec. rate: 3.0%. Has 1,600 employees. Chairman, President & CEO: Alan R. Hodnik. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's earnings are likely to advance significantly this year. The company's main utility subsidiary, Minnesota Power, benefits from current cost recovery for certain kinds of capital projects (renewable, environmental, and transmission). The utility is building a 205-megawatt wind project that should be completed soon at a cost of $345 million. Another project, an environmental upgrade to a 585-mw coal-fired unit, should be completed by April of 2016 at a cost of $250 million. Management is guiding investors towards the upper end of its 2014 earnings target of $2.75-$2.95 a share. Note that our $2.85 estimate *includes* $0.09 of costs that ALLETE is excluding from its guidance.

We forecast another solid profit increase in 2015. Minnesota Power will have a full year of income from the aforementioned wind project. The environmental upgrade will be ongoing. We assume no unusual expenses. Finally, in the fourth quarter of 2015, the company should record a profit (which has not been disclosed) on a $200 million wind project that the its ALLETE Clean Energy subsidiary is developing in North Dakota for Montana-Dakota Utilities.

There should be another boost to the bottom line in 2016. A large industrial customer, Essar Steel, is expanding its production capacity. Originally, production was expected to begin in late 2013, but the project was delayed. Production should finally begin by the second half of 2015, but full production won't be reached until early 2016.

We look for a dividend hike in early 2015. This has been the pattern in recent years. We estimate that the board will boost the quarterly payout by two cents a share (4.1%).

ALLETE's share price has risen just 7% so far this year. This is well below the performance of most electric utility equities in 2014, many of which have surged more than 20%. Perhaps investors were concerned about the delay at Essar Steel. The yield, reflecting the expected dividend hike, is slightly above the utility mean. Total return potential to 2017-2019 is low, but still somewhat better than the industry average.

Paul E. Debbas, CFA *December 19, 2014*

(A) Diluted EPS. Excl. nonrec. gain (loss): '04, 2¢; '05, ($1.84); gain (losses) on disc. ops.: '04, $2.57, '05, (16¢); '06, (2¢); loss from accounting change: '04, 27¢. Next egs. report due mid-Feb. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred chgs. In '12: $6.37/sh. (D) In mill. (E) Rate base: Original cost deprec. Rate allowed on com. eq. in '10: 10.38%; earned on avg. com. eq., '13: 8.3%. Regulatory Climate: Avg. (F) Summer peak in '12 & '13.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	85

ALLIANT ENERGY NYSE-LNT

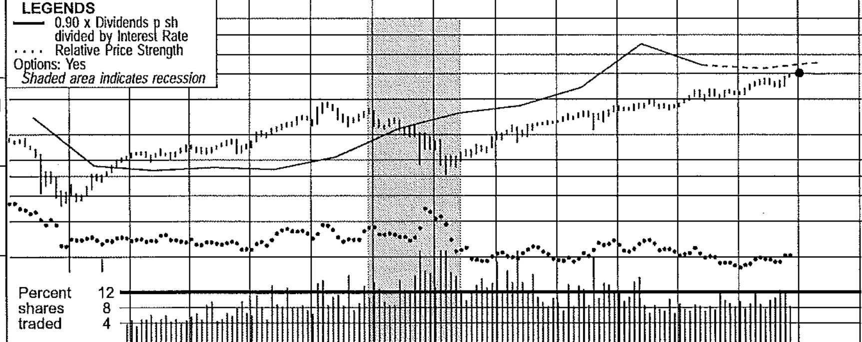
RECENT PRICE **64.63** | P/E RATIO **19.2** (Trailing: 18.6; Median: 14.0) | RELATIVE P/E RATIO **1.04** | DIV'D YLD **3.2%** | VALUE LINE

TIMELINESS **3** Lowered 8/22/14
SAFETY **2** Raised 9/28/07
TECHNICAL **4** Lowered 11/14/14
BETA .80 (1.00 = Market)

High:	25.1	28.8	30.6	40.0	46.5	42.4	31.5	37.7	44.5	47.7	54.2	64.9
Low:	15.0	23.5	25.6	27.5	34.9	22.8	20.3	29.2	33.9	41.9	43.7	50.0

Target Price Range
2017 | 2018 | 2019

LEGENDS
—— 0.90 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+10%)	5%
Low	50	(-25%)	-2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	1	0	0	0	0	1	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	159	160	152
to Sell	145	134	151
Hld's(000)	65696	67528	67088

% TOT. RETURN 11/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	26.5	8.0
3 yr.	65.1	72.4
5 yr.	177.2	119.8

Alliant Energy, formerly called Interstate Energy Corporation, was formed on April 21, 1998 through the merger of WPL Holdings, IES Industries, and Interstate Power. WPL stockholders received one share of Interstate Energy stock for each WPL share, IES stockholders received 1.14 Interstate Energy shares for each IES share, and Interstate Power stockholders received 1.11 Interstate Energy shares for each Interstate Power share.

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
25.56	28.02	28.93	31.15	33.33	31.02	30.81	33.02	27.88	29.54	*30.20*	*31.25*	Revenues per sh	*34.80*
4.69	5.46	4.33	5.12	4.56	4.21	5.21	5.51	5.90	6.68	*6.85*	*6.85*	"Cash Flow" per sh	*7.75*
1.85	2.21	2.06	2.69	2.54	1.89	2.75	2.75	3.05	3.29	*3.45*	*3.60*	Earnings per sh A	*4.10*
1.02	1.05	1.15	1.27	1.40	1.50	1.58	1.70	1.80	1.88	*2.04*	*2.20*	Div'd Decl'd per sh B ■ †	*2.80*
5.55	4.51	3.42	4.91	7.96	10.87	7.82	6.07	10.43	6.63	*7.50*	*8.85*	Cap'l Spending per sh	*9.80*
22.13	20.85	22.83	24.30	25.56	25.07	26.09	27.14	28.25	29.58	*30.50*	*31.35*	Book Value per sh C	*34.65*
115.74	117.04	116.13	110.36	110.45	110.66	110.89	111.02	110.99	110.94	*111.00*	*112.00*	Common Shs Outst'g D	*115.00*
14.0	12.6	16.8	15.1	13.4	13.9	12.5	14.5	14.5	15.3	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.74	.67	.91	.80	.81	.93	.80	.91	.92	.86	*Value Line*		Relative P/E Ratio	*.95*
3.9%	3.8%	3.3%	3.1%	4.1%	5.7%	4.6%	4.3%	4.1%	3.7%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*
2958.7	3279.6	3359.4	3437.6	3681.7	3432.8	3416.1	3665.3	3094.5	3276.8	*3350*	*3500*	Revenues ($mill)	*4000*
229.5	337.8	260.1	320.8	280.0	208.6	303.9	304.4	337.8	364.9	*380*	*405*	Net Profit ($mill)	*470*
26.7%	19.0%	43.8%	44.4%	33.4%	--	30.1%	19.0%	21.5%	12.4%	*15.0%*	*20.0%*	Income Tax Rate	*30.0%*
8.1%	3.0%	3.1%	2.4%	--	--	--	--	8.8%	6.5%	*7.0%*	*7.0%*	AFUDC % to Net Profit	*8.0%*
45.0%	41.6%	31.4%	32.4%	36.3%	44.3%	46.3%	45.7%	48.4%	46.1%	*47.5%*	*47.5%*	Long-Term Debt Ratio	*46.0%*
50.2%	53.1%	62.9%	61.9%	58.6%	51.2%	49.5%	50.9%	48.4%	50.8%	*49.5%*	*49.5%*	Common Equity Ratio	*51.5%*
5104.7	4599.1	4218.4	4329.5	4815.6	5423.0	5840.8	5921.2	6476.6	6461.0	*6650*	*6850*	Total Capital ($mill)	*7800*
5284.6	4866.2	4944.9	4679.9	5353.5	6203.0	6730.6	7037.1	7838.0	7147.3	*8200*	*8500*	Net Plant ($mill)	*9500*
6.1%	8.9%	7.5%	8.6%	7.0%	5.1%	6.6%	6.4%	6.3%	7.0%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
8.2%	12.6%	9.0%	11.0%	9.1%	6.9%	9.7%	9.5%	10.1%	11.0%	*11.0%*	*11.0%*	Return on Shr. Equity	*11.5%*
8.2%	13.1%	9.1%	11.3%	9.3%	6.8%	9.9%	9.5%	10.3%	11.3%	*11.5%*	*11.5%*	Return on Com Equity E	*12.0%*
3.8%	8.1%	4.0%	5.9%	3.8%	.9%	3.8%	3.3%	3.9%	4.9%	*4.0%*	*4.5%*	Retained to Com Eq	*5.0%*
58%	42%	59%	50%	62%	88%	64%	67%	64%	57%	*59%*	*61%*	All Div'ds to Net Prof	*68%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $1984.0 mill. **Due in 5 Yrs** $772.6 mill.
LT Debt $1796.0 mill. **LT Interest** $90.0 mill.
(LT interest earned: 4.2x)

Pension Assets-12/13 $965.6 mill. **Oblig.** $1113.4 mill.
Pfd Stock $200.0 mill. **Pfd Div'd** $10.2 mill.
8,000,000 shs.

Common Stock 110,935,680 shs.

MARKET CAP: $7.2 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+.9	+.3	+.1
Avg. Indust. Use (MWH)	11504	11555	11471
Avg. Indust. Revs. per KWH (¢)	6.51	6.42	6.75
Capacity at Peak (Mw)	5734	5886	5820
Peak Load, Summer (Mw)	5734	5886	5820
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.2	+.3	+.4
Fixed Charge Cov. (%)	302	332	295

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	.5%	-.5%	*4.0%*
"Cash Flow"	2.0%	5.5%	*6.0%*
Earnings	6.0%	4.5%	*6.0%*
Dividends	.5%	7.0%	*4.5%*
Book Value	3.0%	3.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	945.0	819.5	1021.6	879.2	3665.3
2012	765.7	690.3	887.6	750.9	3094.5
2013	859.6	718.0	866.6	832.6	3276.8
2014	952.8	750.3	843.0	*803.9*	*3350*
2015	*950*	*800*	*950*	*800*	*3500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.68	.44	1.12	.51	2.75
2012	.50	.58	1.34	.63	3.05
2013	.72	.59	1.43	.55	3.29
2014	.97	.56	1.40	*.52*	*3.45*
2015	*.85*	*.60*	*1.55*	*.60*	*3.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.395	.395	.395	.395	1.58
2011	.425	.425	.425	.425	1.70
2012	.45	.45	.45	.45	1.80
2013	.47	.47	.47	.47	1.88
2014	.51	.51	.51	.51	

BUSINESS: Alliant Energy Corp., formerly named Interstate Energy, is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies electricity, gas, and other services in Wisconsin, Iowa, and Minnesota. Elect. revs. by state: WI, 47%; IA, 50%; MN, 3%. Elect. rev.: residential, 38%; commercial, 24%; industrial, 29%; wholesale, 7%; other, 2%. Fuel sources, 2013: coal, 48%; nuclear, 17%; gas, 4%; other, 31%. Fuel costs: 50% of revs. 2013 depreciation rate: 5.5%. Estimated plant age: 11 years. Has 3,950 employees. Chairman & Chief Executive Officer: Patricia L. Kampling. Incorporated: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, Wisconsin 53718. Telephone: 608-458-3311. Internet: www.alliantenergy.com.

Alliant Energy had a decent third quarter. The Wisconsin-based utility earned $1.40 a share, on $843 million in revenue. Both of those figures failed to surpass last year's comparable period. Lower profits were driven by the enhanced capital expenditures program, and revenues were dragged down by cooler-than-normal weather, which put a dent in electric sales.

Capital expenditures are going to continue at a brisk pace. Management updated its CapEx plan for 2014-2018 and raised the figure to $5.2 billion (this number includes the new natural gas facility that it plans to build, discussed in the below paragraph). Alliant is building out its electric and gas distribution systems, partly due to a new set of regulatory rules that will be issued in 2015. These new provisions will likely require an acceleration of older pipeline replacements. Moreover, Alliant is also interested in building out its natural gas service. That will help it down the road once carbon emission restrictions become tougher to comply with.

The company is planning to build a 650-megawatt natural gas facility that could replace some of its older units. The new facility would be built alongside the Riverside Energy Center and will cost about $750 million, according to management. The investment in new, highly efficient natural gas generation will provide several significant environmental benefits to the region, and could power more than half a million homes once finished. If regulators approve of the new compound, which is expected, construction will begin in 2016, and the plant should be up and running by early 2019.

A dividend increase of 8% was slightly more than we anticipated. The annualized dividend was raised to $2.20, from $2.04. Based on our earnings projections, we think the dividend can grow 6%-10% a year, due to Alliant's current payout ratio of just below 60%, and its stated payout target of 60%-70%. The company will likely reach the high end of that target within the next 3 to 5 years.

These shares, with their Above-Average Safety rank (2) and low Beta (.80), are best suited for income-oriented investors.

Daniel Henigson *December 19, 2014*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '03, net 24¢; '04, (58¢); '05, ($1.05); '06, 83¢; '07, $1.09; '08, 7¢; '09, (88¢); '10, (15¢); '11, (1¢); '12, (16¢). Next egs. rpt. due early Feb. (B) Div'ds historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. deferred chgs. In '13: $85.8 mill., $0.77/sh. (D) In mill. (E) Rate base: Orig. cost. Rates all'd on com. eq. in IA in '13: 9.5%; in WI in '13 Regul. Clim.: WI, Above Avg.; IA, Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	75

AMERICAN ELEC. PWR. NYSE-AEP

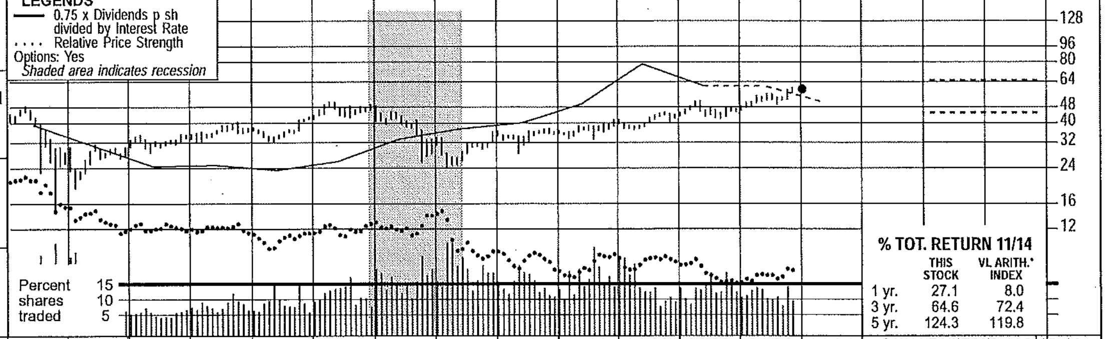
RECENT PRICE 58.87 | P/E RATIO 17.8 (Trailing: 16.5 Median: 13.0) | RELATIVE P/E RATIO 0.96 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 3 Lowered 10/31/14
SAFETY 2 Raised 9/19/14
TECHNICAL 4 Lowered 11/14/14
BETA .70 (1.00 = Market)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
High:	31.5	35.5	40.8	43.1	51.2	49.1	36.5	37.9	41.7	45.4	51.6	59.8
Low:	19.0	28.5	32.3	32.3	41.7	25.5	24.0	28.2	33.1	37.0	41.8	45.8

Target Price Range 2017 | 2018 | 2019

LEGENDS
— 0.75 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+10%)	6%
Low	45	(-25%)	-2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	12	0	0	0	0
to Sell	0	1	0	0	6	0	0	2	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	337	338	325
to Sell	277	267	301
Hld's(000)	317224	323714	326207

% TOT. RETURN 11/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.1	8.0
3 yr.	64.6	72.4
5 yr.	124.3	119.8

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
33.08	35.63	42.53	190.10	42.96	36.82	35.51	30.76	31.82	33.41	35.56	28.22	30.01	31.27	30.77	31.48	*34.70*	*34.55*	Revenues per sh	*39.50*
6.03	6.36	5.11	7.65	6.99	5.76	5.89	5.96	6.67	6.80	6.84	6.32	6.29	6.83	6.64	6.75	*7.20*	*7.45*	"Cash Flow" per sh	*8.75*
2.81	2.69	1.04	3.27	2.86	2.53	2.61	2.64	2.86	2.86	2.99	2.97	2.60	3.13	2.98	3.18	*3.45*	*3.50*	Earnings per sh A	*4.00*
2.40	2.40	2.40	2.40	2.40	1.65	1.40	1.42	1.50	1.58	1.64	1.64	1.71	1.85	1.88	1.95	*2.03*	*2.15*	Div'd Decl'd per sh B ■	*2.50*
4.13	4.47	5.51	5.69	5.08	3.44	4.28	6.11	8.89	8.88	9.83	6.19	5.07	5.74	6.45	7.75	*8.80*	*9.35*	Cap'l Spending per sh	*8.25*
25.24	25.79	25.01	25.54	20.85	19.93	21.32	23.08	23.73	25.17	26.33	27.49	28.33	30.33	31.37	32.98	*34.45*	*35.85*	Book Value per sh C	*40.25*
191.82	194.10	322.02	322.24	338.84	395.02	395.86	393.72	396.67	400.43	406.07	478.05	480.81	483.42	485.67	487.78	*490.00*	*492.00*	Common Shs Outst'g D	*498.00*
17.0	14.3	34.3	13.9	12.7	10.7	12.4	13.7	12.9	16.3	13.1	10.0	13.4	11.9	13.8	14.5	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.88	.82	2.23	.71	.69	.61	.66	.73	.70	.87	.79	.67	.85	.75	.88	.82	*Value Line*		Relative P/E Ratio	*.90*
5.0%	6.2%	6.7%	5.3%	6.6%	6.1%	4.3%	3.9%	4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $19340 mill. Due in 5 Yrs $9356 mill.
LT Debt $15677 mill. LT Interest $713 mill.
Incl. $2230 mill. securitized bonds.
(LT interest earned: 3.7x)

Leases, Uncapitalized Annual rentals $288 mill.
Pension Assets-12/13 $4711 mill. Oblig. $4841 mill.

Pfd Stock None

Common Stock 489,240,481 shs.
as of 10/23/14
MARKET CAP: $29 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
14057	12111	12622	13380	14440	13489	14427	15116	14945	15357	*17000*	*17000*	Revenues ($mill)	*19650*
1038.0	1036.0	1131.0	1147.0	1208.0	1365.0	1248.0	1513.0	1443.0	1549.0	*1630*	*1660*	Net Profit ($mill)	*1975*
33.1%	29.3%	33.0%	31.1%	31.3%	29.7%	34.8%	31.7%	33.9%	36.2%	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
3.6%	5.4%	9.9%	9.8%	9.9%	10.9%	10.4%	10.6%	11.2%	7.3%	*9.0%*	*10.0%*	AFUDC % to Net Profit	*8.0%*
56.2%	54.8%	56.7%	58.3%	59.1%	54.4%	53.1%	50.7%	50.6%	51.1%	*50.5%*	*53.0%*	Long-Term Debt Ratio	*52.0%*
43.1%	44.9%	43.0%	41.4%	40.7%	45.4%	46.7%	49.3%	49.4%	48.9%	*49.5%*	*47.0%*	Common Equity Ratio	*48.0%*
19584	20222	21902	24342	26290	28958	29184	29747	30823	32913	*34050*	*37550*	Total Capital ($mill)	*41800*
22801	24284	26781	29870	32987	34344	35674	36971	38763	40997	*43450*	*46075*	Net Plant ($mill)	*51700*
7.0%	6.6%	6.7%	6.3%	6.2%	6.2%	5.7%	6.6%	6.1%	6.0%	*6.0%*	*5.5%*	Return on Total Cap'l	*6.0%*
12.1%	11.3%	11.9%	11.3%	11.2%	10.3%	9.1%	10.3%	9.5%	9.6%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.0%*
12.2%	11.3%	12.0%	11.4%	11.3%	10.4%	9.1%	10.3%	9.5%	9.6%	*10.0%*	*10.0%*	Return on Com Equity E	*10.0%*
5.7%	5.2%	5.7%	5.1%	5.1%	4.6%	3.1%	4.2%	3.5%	3.7%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
54%	54%	53%	55%	55%	56%	66%	60%	63%	62%	*61%*	*63%*	All Div'ds to Net Prof	*63%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+1.2	-2.1	-1.5
Avg. Indust. Use (MWH)	N A	N A	N A
Avg. Indust. Revs. per KWH (¢)	4.95	4.69	N A
Capacity at Peak (Mw)	N A	N A	N A
Peak Load (Mw)	N A	N A	N A
Annual Load Factor (%)	N A	N A	N A
% Change Customers (yr-end)	N A	N A	N A
Fixed Charge Cov. (%)	286	280	326

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-10.0%	-1.5%	*4.0%*
"Cash Flow"	--	--	*4.5%*
Earnings	.5%	1.5%	*4.5%*
Dividends	-1.5%	4.0%	*4.5%*
Book Value	3.5%	4.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	3730	3609	4333	3444	15116
2012	3625	3551	4156	3613	14945
2013	3826	3582	4176	3773	15357
2014	4648	4044	4302	*4006*	*17000*
2015	*4350*	*4100*	*4500*	*4050*	*17000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.83	.73	1.17	.41	3.13
2012	.80	.75	1.00	.43	2.98
2013	.75	.73	1.10	.60	3.18
2014	1.15	.80	1.01	*.49*	*3.45*
2015	*1.00*	*.80*	*1.15*	*.55*	*3.50*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.41	.42	.42	.46	1.71
2011	.46	.46	.46	.47	1.85
2012	.47	.47	.47	.47	1.88
2013	.47	.49	.49	.50	1.95
2014	.50	.50	.50	.53	

BUSINESS: American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves 5.3 mill. customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia. Electric revenue breakdown: residential, 40%; commercial, 23%; industrial, 19%; wholesale, 15%; other, 3%. Sold 50% stake in Yorkshire Holdings (British utility) '01; sold SEEBOARD (British utility) '02; sold Houston Pipeline '05. Generating sources not available. Fuel costs: 36% of revenues. '13 reported deprec. rates (utility): 1.1%-7.9%. Has 18,500 employees. Chairman, President & CEO: Nicholas K. Akins. Inc.: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Tel.: 614-716-1000. Internet: www.aep.com.

American Electric Power continues to remake itself into a more regulated, less nonregulated company. The company has transferred some of its nonregulated generating assets in Ohio to its regulated utilities in neighboring states. AEP is also asking the Ohio commission to approve a purchased-power agreement (with an effective date of June 1, 2015) for four of its generating plants, totaling 2,671 megawatts of capacity. This would help stabilize the company's income from these units. The majority of AEP's profits now come from the regulated side of its business, and this should continue.

Earnings are likely to advance at a high single-digit pace in 2014. March-quarter earnings were much higher than usual thanks to winter weather that was much colder than normal and higher market prices for power. Our estimate is at the midpoint of AEP's targeted range of $3.40-$3.50 a share.

We look for just slight profit growth in 2015. The first-quarter comparison will be difficult. Even so, there should be some positive factors, most notably rate relief. Higher income from the electric transmission business should be another plus. Our estimate is within AEP's guidance of $3.40-$3.60 a share.

As usual, the company's utilities have some regulatory activity pending. Appalachian Power is not earning an adequate return on equity in West Virginia. So, the company filed for a rate increase of $226 million, based on a 10.62% ROE. The commission's staff was scheduled to put forth its recommendation shortly after this report went to press. An order is due in late May. Kentucky Power is about to file a case. The utility should be able to implement an interim increase in mid-2015.

The board of directors has raised the dividend. The increase was $0.03 a share (6%), three times the hike declared a year earlier. AEP is targeting a payout ratio of 60%-70%.

This stock offers a dividend yield that is just slightly above the average for the electric utility industry. With the recent quotation (like most other electric utility equities) well within our 2017-2019 Target Price Range, total return potential is unspectacular.

Paul E. Debbas, CFA *December 19, 2014*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, ($3.86); '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); discont. ops.: '02, (57¢); '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢. '11 EPS don't add due to rounding. Next egs. report due late Jan. (B) Div'ds historically paid early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '13: $18.20/sh. (D) In mill. (E) Rate base: various. Rates all'd on com. eq.: 9.65%-10.9%; earned on avg. com. eq., '13: 9.9%. Regul. Clim.: Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	90

AMEREN NYSE-AEE

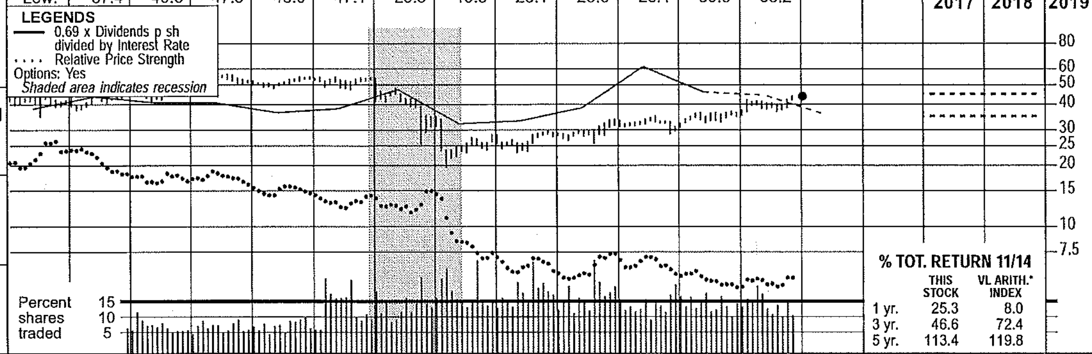
RECENT PRICE 43.87 | P/E RATIO 18.8 (Trailing: 18.2 / Median: 15.0) | RELATIVE P/E RATIO 1.02 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 4 Lowered 12/12/14
SAFETY 2 Raised 6/20/14
TECHNICAL 4 Lowered 11/14/14
BETA .75 (1.00 = Market)

High:	46.5	50.4	56.8	55.2	55.0	54.3	35.3	29.9	34.1	35.3	37.3	44.2
Low:	37.4	40.6	47.5	48.0	47.1	25.5	19.5	23.1	25.5	28.4	30.6	35.2

Target Price Range 2017 | 2018 | 2019

LEGENDS
— 0.69 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+5%)	4%
Low	35	(-20%)	-1%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	1	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	2	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	187	178	167
to Sell	184	189	197
Hld's(000)	154456	159084	160810

% TOT. RETURN 11/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	25.3	8.0
3 yr.	46.6	72.4
5 yr.	113.4	119.8

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
24.18	25.68	28.10	32.64	24.93	28.20	26.43	33.12	33.30	36.23	36.92	29.87	31.77	31.04	28.14	24.06	*24.95*	*26.15*	Revenues per sh	*28.50*
5.36	5.36	6.11	6.33	5.28	6.29	5.57	6.10	6.02	6.76	6.44	6.06	6.33	5.87	5.87	5.25	*5.70*	*6.10*	"Cash Flow" per sh	*7.00*
2.82	2.81	3.33	3.41	2.66	3.14	2.82	3.13	2.66	2.98	2.88	2.78	2.77	2.47	2.41	2.10	*2.35*	*2.55*	Earnings per sh A	*3.00*
2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	1.54	1.54	1.56	1.60	1.60	*1.61*	*1.65*	Div'd Decl'd per sh B ■	*1.80*
2.37	4.16	6.77	7.99	5.11	4.19	4.13	4.63	4.99	6.96	9.75	7.51	4.66	4.50	5.49	5.87	*7.50*	*7.10*	Cap'l Spending per sh	*6.00*
22.27	22.52	23.30	24.26	24.93	26.73	29.71	31.09	31.86	32.41	32.80	33.08	32.15	32.64	27.27	26.97	*27.70*	*28.65*	Book Value per sh C	*32.00*
137.22	137.22	137.22	138.05	154.10	162.90	195.20	204.70	206.60	208.30	212.30	237.40	240.40	242.60	242.63	242.63	*242.65*	*242.65*	Common Shs Outst'g D	*252.00*
14.2	13.5	11.0	12.1	15.8	13.5	16.3	16.7	19.4	17.4	14.2	9.3	9.7	11.9	13.4	16.5	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
.74	.77	.72	.62	.86	.77	.86	.89	1.05	.92	.85	.62	.62	.75	.85	.93	*Value Line*		Relative P/E Ratio	*.85*
6.3%	6.7%	6.9%	6.2%	6.1%	6.0%	5.5%	4.9%	4.9%	4.9%	6.2%	6.0%	5.8%	5.3%	5.0%	4.6%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $6697 mill. Due in 5 Yrs $2276 mill.
LT Debt $5825 mill. LT Interest $317 mill.
(LT interest earned: 3.6x)
Leases, Uncapitalized Annual rentals $14 mill.
Pension Assets-12/13 $3461 mill. Oblig. $3900 mill.
Pfd Stock $142 mill. Pfd Div'd $8 mill.
807,595 sh. $3.50 to $5.50 cum. (no par), $100 stated val., redeem. $102.176-$110/sh.; 616,323 sh. 4.00% to 6.625%, $100 par, redeem. $100-$104/sh.
Common Stock 242,634,798 shs. as of 10/31/14
MARKET CAP: $11 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
5160.0	6780.0	6880.0	7546.0	7839.0	7090.0	7638.0	7531.0	6828.0	5838.0	*6050*	*6350*	Revenues ($mill)	*7200*
541.0	628.0	547.0	629.0	615.0	624.0	669.0	602.0	589.0	518.0	*580*	*630*	Net Profit ($mill)	*775*
34.3%	35.6%	32.7%	33.5%	33.7%	34.7%	36.8%	37.3%	36.9%	37.5%	*39.5%*	*38.5%*	Income Tax Rate	*38.0%*
1.8%	2.9%	.7%	.8%	4.6%	5.8%	7.8%	5.6%	6.1%	7.1%	*7.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
45.5%	44.9%	43.8%	45.0%	47.8%	49.7%	48.2%	45.3%	49.5%	45.2%	*47.0%*	*46.0%*	Long-Term Debt Ratio	*46.0%*
52.6%	53.3%	54.6%	53.4%	50.8%	49.1%	50.9%	53.7%	49.4%	53.7%	*52.0%*	*53.0%*	Common Equity Ratio	*53.0%*
11036	11932	12063	12654	13712	15991	15185	14738	13384	12190	*13000*	*13125*	Total Capital ($mill)	*15200*
13297	13572	14286	15069	16567	17610	17853	18127	16096	16205	*17225*	*18100*	Net Plant ($mill)	*20000*
6.0%	6.5%	5.7%	6.2%	5.7%	5.3%	6.0%	5.6%	6.0%	5.6%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.5%*
9.0%	9.5%	8.1%	9.0%	8.6%	7.8%	8.5%	7.5%	8.7%	7.7%	*8.5%*	*9.0%*	Return on Shr. Equity	*9.5%*
9.1%	9.7%	8.1%	9.2%	8.7%	7.8%	8.6%	7.5%	8.8%	7.8%	*8.5%*	*9.0%*	Return on Com Equity E	*9.5%*
.9%	1.7%	.2%	1.3%	1.0%	3.5%	3.8%	2.8%	3.0%	1.9%	*2.5%*	*3.0%*	Retained to Com Eq	*4.0%*
91%	83%	97%	86%	88%	56%	56%	63%	66%	76%	*68%*	*64%*	All Div'ds to Net Prof	*59%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-1.9	-.7	-.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.93	4.80	4.96
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	295	291	289

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-.5%	-5.0%	.5%
"Cash Flow"	-.5%	-2.5%	3.5%
Earnings	-2.5%	-4.0%	4.5%
Dividends	-4.5%	-9.0%	2.0%
Book Value	1.5%	-2.0%	1.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	1904	1781	2268	1578	7531.0
2012	1658	1660	2001	1509	6828.0
2013	1475	1403	1638	1322	5838.0
2014	1594	1419	1670	*1367*	*6050*
2015	*1650*	*1475*	*1800*	*1425*	*6350*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.29	.57	1.50	.10	2.47
2012	d.11	.87	1.54	.11	2.41
2013	.22	.44	1.25	.19	2.10
2014	.40	.62	1.20	*.13*	*2.35*
2015	*.30*	*.70*	*1.35*	*.20*	*2.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.385	.385	.385	.385	1.54
2011	.385	.385	.385	.40	1.56
2012	.40	.40	.40	.40	1.60
2013	.40	.40	.40	.40	1.60
2014	.40	.40	.40	.41	

BUSINESS: Ameren Corp. is a holding company formed through the merger of Union Electric and CIPSCO. Acquired CILCORP 1/03; Illinois Power 10/04. Has 1.2 mill. electric and 127,000 gas customers in Missouri; 1.2 mill. electric and 811,000 gas customers in Illinois. Discont. power-generation op. in '13. Electric rev. breakdown: residential, 46%; commercial, 33%; industrial, 12%; other, 9%. Generating sources: coal, 70%; nuclear, 11%; hydro, 2%; gas, 1%; purchased, 16%. Fuel costs: 32% of revs. '13 reported depr. rates: 3%-4%. Has 8,500 employees. Chairman: Thomas R. Voss. President & CEO: Warner L. Baxter. Inc.: MO. Address: One Ameren Plaza, 1901 Chouteau Ave., P.O. Box 66149, St. Louis, MO 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

Ameren has an electric rate case pending in Missouri. The utility is seeking a rate increase of $264 million (9.7%), based on a 10.4% return on a 51.6% common-equity ratio. The application is driven by higher net energy costs, infrastructure investments, and increases in certain expenses. The staff of the Missouri Public Service Commission is recommending a $113 million increase, based on an ROE range with a midpoint of 9.25%. A decision is expected in May of 2015, with new tariffs taking effect by June.

Earnings will probably rise materially in 2014 and 2015. Profits in the first half of this year rose sharply, due in part to favorable weather patterns. (The weather turned unfavorable in the third quarter, however.) Ameren is also benefiting from the refinancing of high-cost debt at the parent level earlier this year. In 2015, rate relief and the absence of a refueling outage at the Callaway nuclear plant should boost the bottom line. All told, Ameren is targeting annual earnings growth in a range of 7%-10% through 2018.

Ameren is increasing its focus on electric transmission. The company's five-year capital budget calls for spending $2.25 billion on transmission. Ameren is now allowed a 12.38% ROE on its federally regulated transmission assets, but the Federal Energy Regulatory Commission (FERC) is reviewing the allowed ROEs for transmission owners in the region. In anticipation of a possible reduction in the allowed ROE, Ameren is asking FERC for a half percentage point "adder" to whatever its revised ROE turns out to be because the utility is participating in a regional transmission organization.

The board of directors raised the dividend in the fourth quarter. The quarterly increase was one cent a share (2.5%). This was Ameren's first dividend hike in three years. We project that annual boosts in the disbursement will continue over the 3- to 5-year period. Ameren is targeting a payout ratio in a range of 55%-70%.

Like many utility stocks, Ameren is trading near the upper end of its 2017-2019 Target Price Range. The dividend yield is just slightly above the industry mean, and 3- to 5-year total return potential is low. The stock is untimely.

Paul E. Debbas, CFA *December 19, 2014*

(A) Diluted EPS. Excl. nonrecur. gain (losses): '03, 11¢; '05, (11¢); '10, ($2.19); '11, (32¢); '12, ($6.42); loss from disc. ops.: '13, 92¢. '11 EPS don't add due to rounding. Next egs. report due late Feb. (B) Div'ds histor. paid in late Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '13: $6.90/sh. (D) In mill. (E) Rate base: Orig. cost deprec. Rate allowed on com. eq. in MO in '13: 9.8% elec., in '11: none specified gas; in IL in '14: 8.7% elec., 9.06% gas; earned on avg. com. eq., '13: 7.6%. Regulatory Climate: MO, Avg.; IL, Below Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	5
Earnings Predictability	90

Staff/209
Muldoon/5

AVISTA CORP. NYSE-AVA

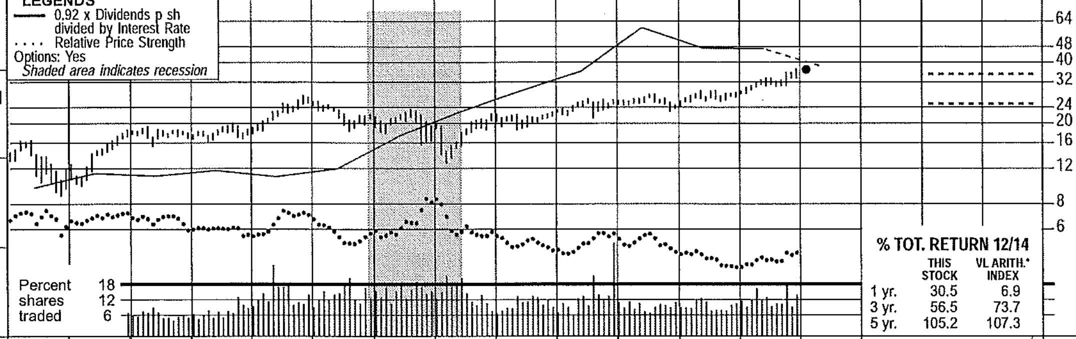
RECENT PRICE 36.87 | P/E RATIO 18.2 (Trailing: 19.3; Median: 16.0) | RELATIVE P/E RATIO 0.99 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 3 Lowered 11/14/14
SAFETY 2 Raised 5/7/10
TECHNICAL 2 Raised 1/16/15
BETA .80 (1.00 = Market)

High:	18.7	19.4	20.2	27.5	25.8	23.6	22.4	22.8	26.5	28.0	29.3	37.4	
Low:	9.8	15.4	16.3	17.6	18.2	15.5	12.7	18.5	21.1	22.8	24.1	27.7	

Target Price Range
2017 | 2018 | 2019

LEGENDS
—— 0.92 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(-5%)	3%
Low	25	(-30%)	-4%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	6	0	1	1	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	118	97	99
to Sell	76	92	107
Hld's(000)	41191	40836	41104

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	30.5	6.9
3 yr.	56.5	73.7
5 yr.	105.2	107.3

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
91.07	221.75	167.59	126.17	20.41	23.24	23.76	27.98	28.68	26.80	30.77	27.58	27.29	27.73	25.86	26.94	23.70	25.00	Revenues per sh	28.25
3.47	2.28	3.31	2.71	2.19	2.63	2.35	2.72	4.27	2.93	3.98	4.45	3.62	3.78	3.70	4.36	4.50	4.65	"Cash Flow" per sh	5.25
1.28	.12	1.76	1.20	.67	1.02	.73	.92	1.47	.72	1.36	1.58	1.65	1.72	1.32	1.85	1.95	2.00	Earnings per sh A	2.25
1.05	.48	.48	.48	.48	.49	.52	.55	.57	.60	.69	.81	1.00	1.10	1.16	1.22	1.27	1.32	Div'd Decl'd per sh B ■	1.50
2.70	3.30	4.24	5.92	1.74	2.21	2.47	3.23	3.14	4.04	4.09	3.86	3.64	4.20	4.61	5.05	5.90	5.85	Cap'l Spending per sh	6.00
11.76	10.69	15.34	15.12	14.84	15.54	15.54	15.87	17.46	17.27	18.30	19.17	19.71	20.30	21.06	21.61	23.90	24.80	Book Value per sh C	26.75
40.45	35.65	47.21	47.63	48.04	48.34	48.47	48.59	52.51	52.91	54.49	54.84	57.12	58.42	59.81	60.08	62.25	63.00	Common Shs Outst'g D	64.50
16.5	NMF	13.6	13.7	19.3	13.8	24.4	19.4	15.4	30.9	15.0	11.4	12.7	14.1	19.3	14.6	16.3		Avg Ann'l P/E Ratio	14.0
.86	NMF	.88	.70	1.05	.79	1.29	1.03	.83	1.64	.90	.76	.81	.88	1.23	.82	.85		Relative P/E Ratio	.90
5.0%	2.8%	2.0%	2.9%	3.7%	3.5%	2.9%	3.0%	2.5%	2.7%	3.4%	4.5%	4.8%	4.5%	4.6%	4.5%	4.0%		Avg Ann'l Div'd Yield	4.8%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $1510.9 mill. **Due in 5 Yrs** $528.2 mill.
LT Debt $1463.8 mill. **LT Interest** $73.2 mill.
Incl. $51.5 mill. debt to affiliated trusts.
(LT interest earned: 3.6x)

Leases, Uncapitalized Annual rentals $6.7 mill.
Pension Assets-12/13 $481.5 mill.
Oblig. $527.0 mill.
Pfd Stock None

Common Stock 62,239,441 shs.
as of 10/31/14
MARKET CAP: $2.3 billion (Mid Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
1151.6	1359.6	1506.3	1417.8	1676.8	1512.6	1558.7	1619.8	1547.0	1618.5	1475	1575	Revenues ($mill)	1825
37.8	47.2	75.1	38.5	73.6	87.1	92.4	100.2	78.2	111.1	120	125	Net Profit ($mill)	145
36.4%	35.4%	35.9%	38.7%	38.3%	34.3%	35.0%	35.4%	34.4%	36.0%	36.5%	36.5%	Income Tax Rate	36.5%
3.7%	3.6%	3.9%	22.4%	14.0%	4.2%	4.0%	5.2%	8.3%	8.8%	10.0%	9.0%	AFUDC % to Net Profit	8.0%
56.5%	58.0%	53.7%	41.0%	48.1%	50.9%	51.6%	51.4%	50.8%	51.4%	50.0%	49.0%	Long-Term Debt Ratio	51.0%
41.9%	40.6%	46.3%	59.0%	51.9%	49.1%	48.4%	48.6%	49.2%	48.6%	50.0%	51.0%	Common Equity Ratio	49.0%
1796.2	1900.8	1980.1	1548.9	1919.5	2139.0	2325.3	2439.9	2561.2	2669.7	2990	3070	Total Capital ($mill)	3525
1956.1	2126.4	2215.0	2351.3	2492.2	2607.0	2714.2	2860.8	3023.7	3202.4	3520	3720	Net Plant ($mill)	4275
4.3%	4.8%	6.1%	5.2%	5.8%	5.5%	5.4%	5.5%	4.3%	5.4%	5.0%	5.5%	Return on Total Cap'l	5.5%
4.8%	5.9%	8.2%	4.2%	7.4%	8.3%	8.2%	8.5%	6.2%	8.6%	8.0%	8.0%	Return on Shr. Equity	8.5%
4.7%	5.9%	8.0%	4.2%	7.4%	8.3%	8.2%	8.5%	6.2%	8.6%	8.0%	8.0%	Return on Com Equity E	8.5%
1.4%	2.4%	4.9%	.8%	3.7%	4.1%	3.3%	3.1%	.8%	2.9%	3.0%	3.0%	Retained to Com Eq	3.0%
72%	60%	40%	82%	50%	51%	60%	64%	88%	66%	65%	65%	All Div'ds to Net Prof	66%

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+2.0	-1.8	+.4
Avg. Indust. Use (MWH)	1556	1505	1428
Avg. Indust. Revs. per KWH (¢)	5.71	5.69	5.74
Capacity at Peak (Mw)	2923	3060	2767
Peak Load, Winter (Mw) F	2381	2485	2223
Annual Load Factor (%)	61.0	58.0	59.0
% Change Customers (yr-end)	+.4	+.6	+1.1
Fixed Charge Cov. (%)	318	245	308

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-7.0%	-1.5%	1.0%
"Cash Flow"	4.5%	1.0%	5.0%
Earnings	5.5%	6.5%	5.5%
Dividends	9.0%	13.5%	4.5%
Book Value	3.5%	3.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	476.6	360.6	343.7	438.9	1619.8
2012	452.3	343.6	340.6	410.5	1547.0
2013	482.9	352.0	335.9	447.7	1618.5
2014	446.6	312.6	301.6	414.2	1475
2015	490	335	325	425	1575

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.73	.39	.18	.42	1.72
2012	.65	.31	.10	.26	1.32
2013	.71	.43	.19	.53	1.85
2014	.79	.43	.16	.57	1.95
2015	.85	.45	.15	.55	2.00

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.275	.275	.275	.275	1.10
2012	.29	.29	.29	.29	1.16
2013	.305	.305	.305	.305	1.22
2014	.3175	.3175	.3175	.3175	1.27
2015					

BUSINESS: Avista Corporation (formerly The Washington Water Power Company) supplies electricity & gas in eastern Washington & northern Idaho. Supplies electricity to part of Alaska & gas to part of Oregon. Customers: 383,000 electric, 326,000 gas. Acq'd Alaska Electric Light and Power 7/14. Sold Ecova energy-management sub. 6/14. Electric rev. breakdown: residential, 32%; commercial, 28%; industrial, 11%; wholesale, 12%; other, 17%. Generating sources: hydro, 27%; gas, 14%; coal, 9%; wood waste, 2%; purchased, 48%. Fuel costs: 43% of revs. '13 reported deprec. rate (utility): 2.9%. Has 1,800 employees. Chairman, President & CEO: Scott L. Morris. Inc.: WA. Address: 1411 E. Mission Ave., Spokane, WA 99202-2600. Tel.: 509-489-0500. Web: www.avistacorp.com.

Avista's regulatory settlement was approved in Washington. Electric and gas rates were raised by $12.3 million (2.5%) and $8.5 million (5.6%), respectively, at the start of 2015. The order didn't address the cost of capital, but it did decouple revenues and volume. Accordingly, top-line advances will now track customer growth (currently at about 1% for electricity and gas), instead of sales changes.

Avista has reached a settlement of its gas rate case in Oregon. If approved by the state regulatory commission, rates will be raised (effective March 1st) by $5.0 million (5.1%), based on a 9.5% return on a 51% common-equity ratio.

More rate applications are probably on the way. Avista will likely file cases in Washington and Idaho for new tariffs in 2016. Alaska Electric Light and Power, which the company acquired in mid-2014, is also considering filing a petition.

We estimate that earnings will increase slightly in 2015. Avista should benefit from rate relief and a full year of income from the Alaska utility acquisition. On the other hand, a favorable swing in power costs helped Avista in Washington in 2014, and we do not assume that this will happen this year. Our 2015 earnings estimate is within the company's targeted range of $1.86-$2.06 a share.

Avista has repurchased some stock, and might buy back more. Through mid-December, the company repurchased 2.5 million shares for $79.9 million. The board authorized a buyback for up to 800,000 more shares in the first quarter of 2015. Later this year, however, Avista will need some equity, so the company expects to issue about $30 million. The company's financing needs also include about $100 million of long-term debt.

We expect a dividend increase this quarter. That has been the pattern in recent years. We estimate that the board of directors will boost the annual payout by $0.05 a share (3.9%). Avista is targeting yearly dividend growth of 4%-5%.

Avista stock offers a dividend yield that is slightly above the utility mean. Like several utility stocks, the recent price is above the upper end of our 2017-2019 Target Price Range. Accordingly, total return potential is low.

Paul E. Debbas, CFA *January 30, 2015*

(A) Dil. EPS. Excl. nonrec. gain (losses): '00, (27¢); '02, (9¢); '03, (3¢); '14, 9¢; gains (losses) on disc. ops.: '01, ($1.00); '02, 2¢; '03, (10¢); '14, $1.17. '13 EPS don't add due to rounding. Next egs. due late Feb. (B) Div'ds histor. paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '13: $8.08/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in WA in '15: none; in ID in '13: 9.8%; in OR in '14: 9.65%; earn. on avg. com. eq., '13: 8.7%. Reg. Clim.: WA, Avg.; ID, Above Avg. (F) Summer pk. '12.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	75

BLACK HILLS CORP. NYSE-BKH

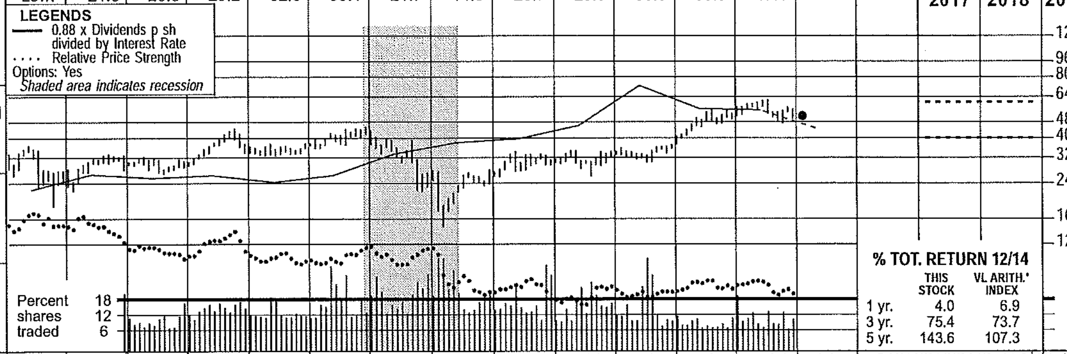
RECENT PRICE	51.40	P/E RATIO	18.2 (Trailing: 20.2 Median: 17.0)	RELATIVE P/E RATIO	0.99	DIV'D YLD	3.1%	VALUE LINE

TIMELINESS **1** Raised 12/12/14
SAFETY **3** Lowered 8/15/03
TECHNICAL **3** Raised 1/9/15
BETA .90 (1.00 = Market)

High:	33.5	32.5	44.6	37.9	45.4	44.0	28.0	34.5	34.8	37.0	55.1	62.1
Low:	21.8	26.5	29.2	32.5	35.4	21.7	14.5	25.7	25.8	30.3	36.9	47.1

Target Price Range 2017 | 2018 | 2019

LEGENDS
— 0.88 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+15%)	7%
Low	40	(-20%)	-2%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	94	85	99
to Sell	96	103	105
Hld's(000)	31901	32363	32908

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.0	6.9
3 yr.	75.4	73.7
5 yr.	143.6	107.3

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
31.48	37.05	69.69	57.96	15.74	35.17	34.54	41.97	19.69	18.41	26.03	32.58	33.29	28.96	26.55	28.67	30.75	30.65	Revenues per sh	33.50
2.72	2.88	3.68	5.27	4.93	4.26	4.46	4.81	5.04	5.29	2.95	5.41	4.88	4.01	5.59	5.93	6.40	6.55	"Cash Flow" per sh	7.50
1.60	1.70	2.37	3.42	2.33	1.84	1.74	2.11	2.21	2.68	.18	2.32	1.66	1.01	1.97	2.61	2.90	2.85	Earnings per sh A	3.25
1.00	1.04	1.08	1.12	1.16	1.20	1.24	1.28	1.32	1.37	1.40	1.42	1.44	1.46	1.48	1.52	1.56	1.60	Div'd Decl'd per sh B ■	1.85
1.18	4.89	5.79	14.07	8.65	2.80	2.80	4.18	9.24	6.92	8.51	8.90	12.04	10.03	7.90	7.97	9.35	9.60	Cap'l Spending per sh	8.25
9.58	10.14	11.95	18.95	19.66	21.72	22.43	22.29	23.68	25.66	27.19	27.84	28.02	27.53	27.88	29.39	30.70	31.90	Book Value per sh C	35.75
21.58	21.37	23.30	26.89	26.93	32.30	32.48	33.16	33.37	37.80	38.64	38.97	39.27	43.92	44.21	44.50	44.75	45.00	Common Shs Outst'g D	45.75
14.9	13.6	10.9	11.4	12.5	15.9	17.1	17.3	15.8	15.0	NMF	9.9	18.1	NMF	17.1	18.2	19.0		Avg Ann'l P/E Ratio	15.5
.77	.78	.71	.58	.68	.91	.90	.92	.85	.80	NMF	.66	1.15	NMF	1.09	1.03	1.00		Relative P/E Ratio	.95
4.2%	4.5%	4.2%	2.9%	4.0%	4.1%	4.2%	3.5%	3.8%	3.4%	4.2%	6.2%	4.8%	4.6%	4.4%	3.2%	2.8%		Avg Ann'l Div'd Yield	3.7%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $1566.5 mill. Due in 5 Yrs $459.0 mill.
LT Debt $1107.5 mill. LT Interest $57.6 mill.
(LT interest earned: 4.1x)
Leases, Uncapitalized Annual rentals $2.8 mill.

Pension Assets-12/13 $280.4 mill. Oblig. $321.4 mill.

Pfd Stock None

Common Stock 44,655,369 shs. as of 10/31/14

MARKET CAP: $2.3 billion (Mid Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
1121.7	1391.6	656.9	695.9	1005.8	1269.6	1307.3	1272.2	1173.9	1275.9	1375	1380	Revenues ($mill)	1530
57.2	70.3	74.0	100.1	6.8	89.7	64.6	40.4	86.9	115.8	130	130	Net Profit ($mill)	145
31.8%	33.8%	31.3%	31.3%	33.1%	30.7%	26.4%	31.1%	35.5%	34.7%	33.5%	34.5%	Income Tax Rate	34.5%
.3%	1.0%	9.7%	14.8%	173.2%	20.1%	28.0%	65.0%	5.4%	2.4%	2.0%	2.0%	AFUDC % to Net Profit	2.0%
49.9%	47.6%	44.3%	36.8%	32.3%	48.4%	51.9%	51.4%	43.2%	51.6%	53.0%	52.0%	Long-Term Debt Ratio	53.5%
49.6%	52.4%	55.7%	63.2%	67.7%	51.6%	48.1%	48.6%	56.8%	48.4%	47.0%	48.0%	Common Equity Ratio	46.5%
1469.3	1409.1	1418.4	1534.2	1551.8	2100.7	2286.3	2489.7	2171.4	2704.7	2910	2995	Total Capital ($mill)	3500
1445.7	1435.4	1646.4	1823.5	2022.2	2160.7	2495.4	2789.6	2742.7	2990.3	3255	3520	Net Plant ($mill)	4150
5.3%	6.6%	6.8%	7.9%	1.6%	5.9%	4.4%	3.3%	5.5%	5.5%	5.5%	5.5%	Return on Total Cap'l	5.5%
7.8%	9.5%	9.4%	10.3%	.7%	8.3%	5.9%	3.3%	7.1%	8.9%	9.5%	9.0%	Return on Shr. Equity	9.0%
7.8%	9.5%	9.4%	10.3%	.7%	8.3%	5.9%	3.3%	7.1%	8.9%	9.5%	9.0%	Return on Com Equity E	9.0%
2.3%	3.8%	3.8%	5.1%	NMF	3.2%	.7%	NMF	1.8%	3.7%	4.5%	4.0%	Retained to Com Eq	4.0%
71%	60%	59%	50%	NMF	62%	87%	NMF	75%	58%	53%	55%	All Div'ds to Net Prof	57%

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+1.3	+.2	+1.0
Avg. Indust. Use (MWH)	8482	8921	9740
Avg. Indust. Revs. per KWH (¢)	7.58	8.01	8.19
Capacity at Yearend (Mw)	1315	1318	NA
Peak Load, Summer (Mw)	1025	1036	988
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+.3	+.8
Fixed Charge Cov. (%)	160	205	224

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-2.5%	5.5%	3.0%
"Cash Flow"	.5%	3.0%	6.5%
Earnings	-3.0%	2.0%	9.5%
Dividends	2.5%	1.5%	3.5%
Book Value	3.5%	2.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	400.8	260.7	249.5	361.2	1272.2
2012	365.8	242.4	246.8	318.9	1173.9
2013	380.7	279.8	259.9	355.5	1275.9
2014	460.2	283.2	272.1	359.5	1375
2015	430	290	280	380	1380

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.73	.09	d.29	.44	1.01
2012	.80	.11	.38	.68	1.97
2013	.97	.69	.52	.43	2.61
2014	1.08	.44	.60	.78	2.90
2015	1.00	.45	.60	.80	2.85

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.365	.365	.365	.365	1.46
2012	.37	.37	.37	.37	1.48
2013	.38	.38	.38	.38	1.52
2014	.39	.39	.39	.39	1.56
2015					

BUSINESS: Black Hills Corporation is a holding company for utilities that serve 204,000 electric customers in CO, SD, WY and MT, and 574,000 gas customers in NE, IA, KS, CO and WY. Mines coal & has a gas & oil E&P business. Acq'd Mallon Resources 3/03; Cheyenne Light 1/05; utility operations from Aquila 7/08. Discontinued telecom in '05; oil marketing in '06; gas marketing in '11. Electric revenue breakdown: res'l, 31%; comm'l, 36%; ind'l, 14%; wholesale, 11%; other, 8%. Generating sources: coal, 36%; other, 4%; purchased, 60%. Fuel costs: 41% of revs. '13 depr. rate: 3.5%. Has 1,900 empls. Chairman, President & CEO: David R. Emery. Inc.: SD. Address: P.O. Box 1400, 625 Ninth St., Rapid City, SD 57701. Tel.: 605-721-1700. Internet: www.blackhillscorp.com.

The price of Black Hills stock has been significantly affected by the price of oil in the past two years. When oil prices were high in 2013, this equity was one of the top performers in the electric utility industry. In 2014, when oil prices declined precipitously, the share price rose just 1% in a year in which most utility issues fared extremely well. Oil and natural gas prices are continuing to decline. So far, Black Hills' oil and gas exploration and production subsidiary has not announced a cutback in its drilling or capital spending plans, but this might change when the company announces earnings in early February.

We estimate that earnings will decline slightly in 2015. In early November, Black Hills put forth 2015 profit guidance of $2.90-$3.10 a share. However, this was based on higher commodity prices than are likely to occur this year. Although the company has hedged some of its expected 2015 production, there is little doubt that it will feel the effects of lower oil and gas prices. Thus, our earnings estimate of $2.85 a share is below the low end of management's guidance.

The utility received rate increases in two states. In Kansas, the commission approved a "black box" settlement (i.e., no specified return on equity) calling for a $5.2 million raise in gas rates. In Colorado, electric rates were raised by $3 million, based on a return of 9.83% on a common-equity ratio of 50.17%. Each tariff hike took effect at the start of the new year. Black Hills is awaiting a final order in its electric rate case in South Dakota, in which the utility sought an increase of $14.6 million, based on a 10.25% return on equity.

We expect a dividend increase in the current quarter. A first-period hike in the disbursement has been the practice of the board of directors for many years. We estimate that the board will boost the quarterly dividend by a cent a share (2.6%). The company's payout ratio is low enough to allow for an increase, despite the possibility of lower earnings in 2015.

This timely stock has a dividend yield that is a cut below the utility mean. It does not stand out for its 3- to 5-year total return potential.

Paul E. Debbas, CFA *January 30, 2015*

(A) Diluted EPS. Excl. nonrec. gains (losses): '05, (99¢); '08, ($1.55); '09, (28¢); '10, 10¢; '12, 4¢ net; gains (losses) on disc. ops.: '05, (7¢); '06, 21¢; '07, (4¢); '08, $4.12; '09, 7¢; '11, 23¢; '12, (16¢). '11, '12 EPS don't add due to chng. in shs. or rounding. Next egs. due early Feb. (B) Div'ds paid early Mar., Jun., Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '13: $11.12/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in SD in '13: none specified; in CO in '15: 9.83%; earned on avg. com. eq., '13: 9.1%. Regul. Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	65
Earnings Predictability	40

Staff/209
Muldoon/7

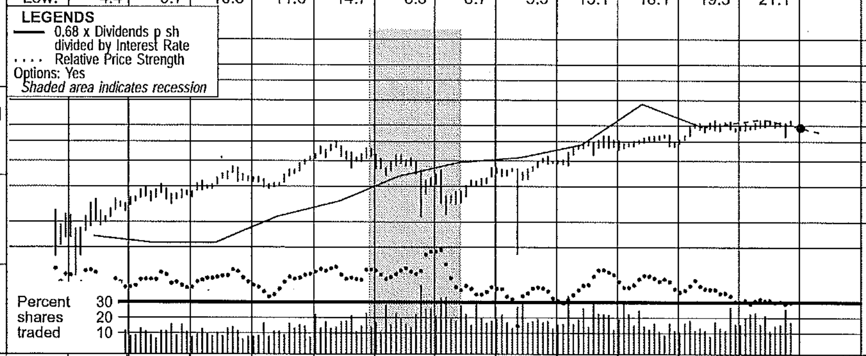
CENTERPOINT EN'RGY NYSE-CNP

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
23.45	18.5	(Trailing: 18.5; Median: 15.0)	1.00	4.4%	VALUE LINE

TIMELINESS 3 Raised 6/13/14
SAFETY 2 Raised 9/21/12
TECHNICAL 3 Raised 12/19/14
BETA .75 (1.00 = Market)

High:	10.5	12.3	15.1	16.9	20.2	17.3	14.9	17.0	21.5	21.8	25.7	25.8	
Low:	4.4	9.7	10.5	11.6	14.7	8.5	8.7	5.5	15.1	18.1	19.3	21.1	

Target Price Range
2017 | 2018 | 2019



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+30%)	11%
Low	25	(+5%)	7%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	1	1	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	184	173	178
to Sell	192	204	172
Hld's(000)	326992	332822	332188

% TOT. RETURN 11/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.3	8.0
3 yr.	35.1	72.4
5 yr.	123.1	119.8

1998	1999	2000	2001A	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
--	--	--	35.18	26.40	31.87	27.63	31.33	29.71	29.82	32.71	21.14	20.69	19.83	17.43	18.90	*21.40*	*21.35*	Revenues per sh	*24.50*
--	--	--	3.69	3.34	3.98	2.56	2.72	3.47	3.39	3.42	2.94	3.14	3.43	3.89	3.54	*3.60*	*3.70*	"Cash Flow" per sh	*4.25*
--	--	--	1.54	1.29	1.37	.61	.67	1.33	1.17	1.30	1.01	1.07	1.27	1.35	1.24	*1.30*	*1.30*	Earnings per sh B	*1.75*
--	--	--	1.50	1.07	.40	.40	.40	.60	.68	.73	.76	.78	.79	.81	.83	*.95*	*1.03*	Div'd Decl'd per sh C ■	*1.30*
--	--	--	6.78	2.85	2.11	1.72	2.23	3.21	3.45	2.95	2.96	3.55	3.06	2.84	3.00	*3.20*	*3.25*	Cap'l Spending per sh	*2.75*
--	--	--	22.24	4.74	5.75	3.59	4.18	4.96	5.61	5.89	6.74	7.53	9.91	10.06	10.09	*10.40*	*10.70*	Book Value per sh D	*11.75*
--	--	--	302.94	300.10	306.30	308.05	310.33	313.65	322.72	346.09	391.75	424.70	426.03	427.44	429.00	*430.00*	*431.00*	Common Shs Outst'g E	*434.00*
--	--	--	--	5.6	6.0	17.8	19.1	10.3	15.0	11.3	11.8	13.8	14.6	14.8	18.7	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
--	--	--	--	.31	.34	.94	1.02	.56	.80	.68	.79	.88	.92	.94	1.06	*Value Line*		Relative P/E Ratio	*1.00*
--	--	--	--	14.8%	4.8%	3.7%	3.1%	4.4%	3.9%	5.0%	6.4%	5.3%	4.3%	4.0%	3.6%	*estimates*		Avg Ann'l Div'd Yield	*4.7%*
						8510.4	9722.0	9319.0	9623.0	11322	8281.0	8785.0	8450.0	7452.0	8106.0	*9200*	*9200*	Revenues ($mill)	*10650*
						205.7	225.0	432.0	399.0	447.0	372.0	442.0	546.0	581.0	536.0	*555*	*565*	Net Profit ($mill)	*770*
						40.2%	40.5%	12.6%	32.8%	38.3%	32.1%	37.3%	33.6%	33.4%	31.4%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
						1.9%	1.8%	2.3%	5.5%	2.7%	1.3%	2.7%	1.6%	2.6%	3.5%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*2.0%*
						86.7%	86.9%	83.4%	82.2%	83.3%	77.6%	73.8%	67.2%	66.0%	64.4%	*63.0%*	*62.0%*	Long-Term Debt Ratio	*58.0%*
						13.3%	13.1%	16.6%	17.8%	16.7%	22.4%	26.2%	32.8%	34.0%	35.6%	*37.0%*	*38.0%*	Common Equity Ratio	*42.0%*
						8298.5	9864.0	9358.0	10174	12218	11758	12199	12863	12658	12146	*12100*	*12150*	Total Capital ($mill)	*12300*
						8186.4	8492.0	9204.0	9740.0	10296	10788	11732	12402	13597	9593.0	*10225*	*10825*	Net Plant ($mill)	*12000*
						6.8%	5.3%	7.8%	6.9%	6.0%	5.8%	6.1%	6.4%	6.8%	6.3%	*6.0%*	*6.0%*	Return on Total Cap'l	*8.0%*
						18.6%	17.4%	27.8%	22.0%	21.9%	14.1%	13.8%	12.9%	13.5%	12.4%	*12.5%*	*12.5%*	Return on Shr. Equity	*15.0%*
						18.6%	17.4%	27.8%	22.0%	21.9%	14.1%	13.8%	12.9%	13.5%	12.4%	*12.5%*	*12.5%*	Return on Com Equity F	*15.0%*
						7.5%	7.8%	15.7%	10.0%	9.9%	3.6%	3.8%	5.0%	5.5%	4.2%	*3.5%*	*2.5%*	Retained to Com Eq	*4.0%*
						60%	55%	43%	55%	55%	74%	72%	62%	60%	66%	*73%*	*78%*	All Div'ds to Net Prof	*73%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $8599 mill. **Due in 5 Yrs** $3988 mill.
LT Debt $7797 mill. **LT Interest** $398 mill.
Incl. $2736 mill. securitized transition & system restoration bonds.
(LT interest earned: 2.6x)
Leases, Uncapitalized Annual rentals $6 mill.
Pension Assets-12/13 $1803 mill.
Oblig. $2153 mill.

Pfd Stock None
Common Stock 429,795,830 shs.
as of 10/22/14
MARKET CAP: $10 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+3.9	-1.8	+1.8
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+2.1	+2.0	+2.0
Fixed Charge Cov. (%)	221	223	204

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-5.0%	-9.5%	4.5%
"Cash Flow"	--	1.0%	3.5%
Earnings	-1.0%	.5%	5.0%
Dividends	-2.0%	4.0%	8.0%
Book Value	-1.0%	13.0%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2011	2587	1837	1881	2145	8450.0
2012	2084	1525	1705	2138	7452.0
2013	2388	1894	1640	2184	8106.0
2014	3163	1884	1807	*2346*	*9200*
2015	*2750*	*2000*	*2000*	*2450*	*9200*

Cal-endar	EARNINGS PER SHARE B Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2011	.35	.28	.38	.27	1.27
2012	.34	.29	.40	.31	1.35
2013	.34	.29	.35	.26	1.24
2014	.43	.25	.33	*.29*	*1.30*
2015	*.37*	*.28*	*.35*	*.30*	*1.30*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.195	.195	.195	.195	.78
2011	.1975	.1975	.1975	.1975	.79
2012	.2025	.2025	.2025	.2025	.81
2013	.2075	.2075	.2075	.2075	.83
2014	.2375	.2375	.2375	.2375	

BUSINESS: CenterPoint Energy, Inc. is a holding company for Houston Electric, which serves 2.1 million customers in Houston and environs, and gas utilities with 3.3 million customers: Entex (Texas, Louisiana, Mississippi); Arkla (Arkansas, Louisiana, Oklahoma, Texas); and Minnegasco (Minnesota). Owns 55.4% of Enable Midstream Partners. Discontinued Texas Genco Holdings in '04. Electric rev. breakdown: residential, 52%; commercial, 31%; industrial, 15%; other, 2%. Does not own generating assets. Gas costs: 48% of revs. '13 deprec. rate: 7.0%. Has 8,600 employees. Chairman: Milton Carroll. Pres. & CEO: Scott M. Prochazka. Inc.: TX. Address: 1111 Louisiana, P.O. Box 4567, Houston, TX 77210-4567. Tel.: 713-207-1111. Internet: www.centerpointenergy.com.

CenterPoint Energy's shareholders can expect a solid dividend increase in the first quarter of 2015. The company has established a goal of annual dividend hikes of 8%-10% over the next three years. This is based on paying out 60%-70% of its "sustainable" income from its utility operations and 90%-100% of its net aftertax distributions from its 55.4% ownership of Enable Midstream Partners. (Enable distributed $227 million to CenterPoint in the first nine months of 2014.) We estimate that the board of directors will raise the annual disbursement by $0.08 a share (8.4%), to $1.03 a share.

We estimate that earnings will rise 5% in 2014. The transaction that formed the Enable master limited partnership was dilutive to CenterPoint's earnings, but the company benefited from $0.10 a share of mark-to-market gains in the first three quarters.

We forecast flat profits in 2015. The first-quarter earnings comparison is difficult because the winter weather was much colder than normal. We assume a return to normal weather patterns next year.

The Texas Public Utility Commission ruled that CenterPoint may have a 50% stake in a transmission line that will be built by the summer of 2018. CenterPoint had wanted to build the entire project, which has a preliminary cost estimate of $600 million. A certificate of need and other approvals are required before construction can begin. The approval process should take about 12 months.

Otherwise, all is quiet on the regulatory front. Most of CenterPoint's utilities benefit from regulatory mechanisms that enable them to offset regulatory lag and thus earn adequate returns on equity. The one exception is the gas company in Minnesota, which received a $33 million rate increase earlier this year.

CenterPoint stock has risen just 1% so far in 2014. This is far below most electric utility equities, many of which have soared more than 20%. Investor concerns (excessive, in our view) about the effect of falling oil prices on Enable have hurt CenterPoint's stock. The dividend yield is above average for a utility, as is the 3- to 5-year total return potential.

Paul E. Debbas, CFA *December 19, 2014*

(A) Pro forma data. (B) Diluted EPS. Excl. extraordinary gains (losses): '04, ($2.72); '05, 9¢; '11, $1.89; '12, (38¢) net; '13, (52¢); gain (losses) on disc. ops.: '03, 2¢; '04, (37¢); '05, (1¢). '11 & '12 EPS don't add due to rounding. Next egs. report due late Feb. (C) Div'ds historically paid in early Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (D) Incl. intang. In '13: $10.64/sh. (E) In mill. (F) Rate base: Net orig. cost. Rate all'd on com. eq. (elec.) in '11: 10%; (gas): 9.45%-11.25%; earned on avg. com. eq., '13: 12.0%. Regulatory Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	80
Earnings Predictability	90

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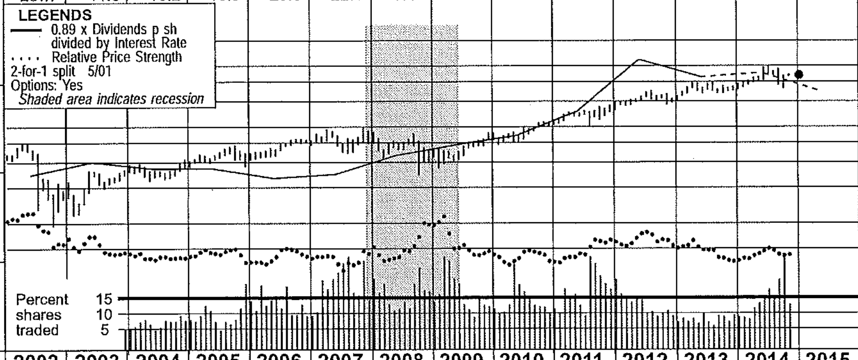
CLECO CORPORATION NYSE-CNL

RECENT PRICE	53.86	P/E RATIO	21.0 (Trailing: 20.6; Median: 14.0)	RELATIVE P/E RATIO	1.14	DIV'D YLD	3.0%	VALUE LINE

TIMELINESS – Suspended 10/31/14
SAFETY 1 Raised 6/22/12
TECHNICAL – Suspended 10/31/14
BETA .80 (1.00 = Market)

High:	18.4	20.8	24.4	26.2	29.8	28.4	28.1	31.8	38.3	45.3	50.4	59.2	
Low:	11.0	16.2	18.9	20.5	22.1	17.3	18.7	24.3	30.1	36.2	40.4	45.5	

Target Price Range 2017 | 2018 | 2019



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(-5%)	2%
Low	45	(-15%)	-1%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	6	0	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	103	114	106
to Sell	86	112	122
Hld's(000)	44490	44575	44513

% TOT. RETURN 11/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	21.1	8.0
3 yr.	63.0	72.4
5 yr.	147.1	119.8

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
11.46	17.12	18.23	23.55	15.33	18.54	15.03	18.41	17.38	17.19	17.99	14.17	18.98	18.53	16.46	18.14	*21.10*	*21.50*	Revenues per sh	*24.00*
2.28	2.36	2.77	2.94	3.05	2.98	2.56	2.76	2.63	2.69	3.71	3.78	5.12	5.28	5.40	5.32	*5.45*	*5.30*	"Cash Flow" per sh	*6.50*
1.12	1.19	1.46	1.51	1.52	1.26	1.32	1.42	1.36	1.32	1.70	1.76	2.29	2.59	2.70	2.65	*2.70*	*2.35*	Earnings per sh A	*3.00*
.81	.83	.85	.87	.90	.90	.90	.90	.90	.90	.90	.90	.98	1.12	1.30	1.43	*1.56*	*1.60*	Div'd Decl'd per sh B ■	*2.00*
2.09	3.99	2.52	1.10	1.91	1.58	1.61	3.19	4.11	8.51	5.59	4.15	4.68	3.25	4.06	3.12	*3.55*	*2.60*	Cap'l Spending per sh	*3.00*
9.07	9.44	10.04	10.69	11.77	10.09	10.83	13.69	15.22	16.85	17.65	18.50	21.76	23.55	24.84	26.24	*27.20*	*27.95*	Book Value per sh C	*30.50*
44.97	44.88	44.99	44.96	47.04	47.18	49.62	49.99	57.57	59.94	60.04	60.26	60.53	60.29	60.36	60.45	*60.40*	*60.50*	Common Shs Outst'g D	*60.50*
14.4	13.4	13.2	14.6	12.2	12.4	13.8	15.0	17.3	19.6	14.1	13.2	12.3	13.3	15.0	17.3	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.75	.76	.86	.75	.67	.71	.73	.80	.93	1.04	.85	.88	.78	.83	.95	.97	*Value Line*		Relative P/E Ratio	*1.00*
5.0%	5.2%	4.4%	3.9%	4.8%	5.8%	5.0%	4.2%	3.8%	3.5%	3.8%	3.9%	3.5%	3.3%	3.2%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*
						745.8	920.2	1000.7	1030.6	1080.2	853.8	1148.7	1117.3	993.7	1096.7	*1275*	*1300*	Revenues ($mill)	*1450*
						66.1	75.0	74.7	79.6	102.1	106.3	139.5	157.8	163.6	160.7	*165*	*145*	Net Profit ($mill)	*180*
						35.2%	39.2%	36.0%	24.3%	15.3%	8.3%	44.1%	30.6%	28.5%	33.1%	*34.0%*	*36.0%*	Income Tax Rate	*38.5%*
						7.5%	4.3%	14.2%	57.9%	82.8%	93.5%	12.2%	4.3%	5.5%	3.4%	*5.0%*	*3.0%*	AFUDC % to Net Profit	*2.0%*
						44.5%	46.3%	40.9%	43.2%	51.1%	54.2%	51.5%	48.5%	45.6%	45.3%	*42.5%*	*43.0%*	Long-Term Debt Ratio	*35.5%*
						53.1%	52.0%	57.8%	56.7%	48.9%	45.8%	48.5%	51.5%	54.4%	54.7%	*57.5%*	*57.0%*	Common Equity Ratio	*64.5%*
						1011.6	1315.9	1515.6	1780.5	2167.7	2436.4	2717.9	2756.9	2756.5	2901.7	*2860*	*2955*	Total Capital ($mill)	*2875*
						1060.0	1188.7	1304.9	1725.9	2045.3	2247.0	2784.2	2893.9	3009.5	3083.1	*3130*	*3115*	Net Plant ($mill)	*3050*
						8.9%	7.1%	6.3%	5.6%	6.1%	5.9%	6.6%	7.0%	7.3%	6.8%	*7.0%*	*6.0%*	Return on Total Cap'l	*7.5%*
						11.8%	10.6%	8.3%	7.9%	9.6%	9.5%	10.6%	11.1%	10.9%	10.1%	*10.0%*	*8.5%*	Return on Shr. Equity	*9.5%*
						11.9%	10.7%	8.3%	7.8%	9.6%	9.5%	10.6%	11.1%	10.9%	10.1%	*10.0%*	*8.5%*	Return on Com Equity E	*9.5%*
						3.9%	4.1%	3.0%	2.6%	4.5%	4.7%	6.1%	6.3%	5.7%	4.7%	*4.0%*	*3.0%*	Retained to Com Eq	*3.0%*
						68%	62%	65%	68%	53%	51%	42%	43%	48%	54%	*58%*	*67%*	All Div'ds to Net Prof	*67%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $1338.4 mill. **Due in 5 Yrs** $453.8 mill.
LT Debt $1320.2 mill. **LT Interest** $72.7 mill.
Incl. $6.9 million capitalized leases.
(LT interest earned: 4.4x)

Leases, Uncapitalized Annual rentals $10.6 mill.
Pension Assets-12/13 $384.6 mill. **Oblig.** $392.5 mill.

Pfd Stock None

Common Stock 60,377,666 shs.
as of 10/22/14
MARKET CAP: $3.3 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+.4	-3.4	+1.4
Avg. Indust. Use (MWH)	3904	3814	3870
Avg. Indust. Revs. per KWH (¢)	7.58	6.83	7.50
Capacity at Peak (Mw)	2544	3315	3315
Peak Load, Summer (Mw)	2355	2282	2278
Annual Load Factor (%)	56.2	55.1	57.0
% Change Customers (avg.)	+.6	+.6	+.6
Fixed Charge Cov. (%)	415	326	360

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-1.0%	--	*5.0%*
"Cash Flow"	6.0%	12.0%	*3.5%*
Earnings	6.5%	12.5%	*2.0%*
Dividends	3.5%	7.5%	*7.5%*
Book Value	8.5%	8.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	253.7	272.9	351.6	239.1	1117.3
2012	222.8	240.1	297.4	233.4	993.7
2013	240.9	263.9	328.8	263.1	1096.7
2014	284.4	309.1	371.4	*310.1*	*1275*
2015	*280*	*315*	*390*	*315*	*1300*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.48	.52	1.08	.51	2.59
2012	.50	.77	1.05	.38	2.70
2013	.45	.69	1.09	.41	2.65
2014	.43	.60	1.17	*.50*	*2.70*
2015	*.35*	*.55*	*1.10*	*.35*	*2.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.225	.25	.25	.25	.98
2011	.25	.28	.28	.3125	1.12
2012	.3125	.3125	.3375	.3375	1.30
2013	.3375	.3625	.3625	.3625	1.43
2014	.3625	.40	.40	.40	

BUSINESS: Cleco Corporation is a holding company for Cleco Power LLC, which supplies electricity to about 284,000 customers in central Louisiana. Electric revenue breakdown: residential, 46%; commercial, 30%; industrial, 14%; other, 10%. Largest industrial customers are paper mills and other wood-product industries. Generating sources: gas & oil, 29%; coal & lignite, 28%; petroleum coke, 27%; purchased, 16%. Fuel costs: 34% of revenues. '13 reported depreciation rate (utility): 2.7%. Has 1,200 employees. Chairman: J. Patrick Garrett. President & CEO: Bruce A. Williamson. Incorporated: Louisiana. Address: 2030 Donahue Ferry Road, P.O. Box 5000, Pineville, Louisiana 71361-5000. Telephone: 318-484-7400. Internet: www.cleco.com.

Cleco has accepted a takeover offer. The bid came as no surprise. In June, after rumors came out that the company was a target, Cleco announced that it had retained financial and legal advisors in response to a prospective buyer's expression of interest. An investor group led by Macquarie Infrastructure Partners and British Columbia Investment Management has agreed to pay $55.37 a share in cash for each Cleco share. The acquisition requires the approval of Cleco shareholders, the Louisiana Public Service Commission, and the Federal Energy Regulatory Commission. The company expects the transaction to be completed in the second half of 2015. (Note that a dividend hike appears unlikely as long as the deal is pending.) Due to the takeover agreement, we have suspended the Timeliness rank of Cleco stock.

We advise stockholders to sell their shares on the open market. The offer is very generous, at more than 20 times estimated 2015 earnings. However, with the recent price just 3% below the buyout price, there is little upside potential for investors. By selling now, shareholders can avoid the risk that the deal fails to win regulatory approval. This frequently happens in the electric utility industry, although we note that Macquarie has completed three domestic utility acquisitions (two electric and one water).

Earnings are likely to decline in 2015. Next year will be the first full year under Cleco's new formula rate plan. The new plan cut the utility's allowed return on equity significantly. This will have a far greater effect on earnings than we had estimated. The tax rate will probably be higher than in 2014. Putting it all together, we have cut our 2015 profit forecast by $0.50 a share, to $2.35. Our revised estimate is within Cleco's guidance of $2.28-$2.38 a share. Note that the company is excluding any deal-related expenses from this range, but we will include them in our earnings presentation.

Finances are solid. The fixed-charge coverage and common-equity ratio are above average for this industry. The utility should have no trouble financing its capital budget. All told, Cleco merits a Financial Strength rating of A.

Paul E. Debbas, CFA *December 19, 2014*

(A) Diluted earnings. Excl. nonrec. gains (losses): '00, 5¢; '02, (5¢), '03, ($2.05); '05, $2.11; '07, $1.22; '10, $1.91; '11, 63¢; losses from discont. ops.: '00, 14¢; '01, 4¢. '13 EPS don't add due to rounding. Next earnings report due early Feb. (B) Div'ds historically paid in mid-Feb., May, Aug. and Nov. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '13: $10.13/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '14: 11.24%; earned on avg. com. eq., '13: 10.4%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	80

CMS ENERGY CORP. NYSE-CMS

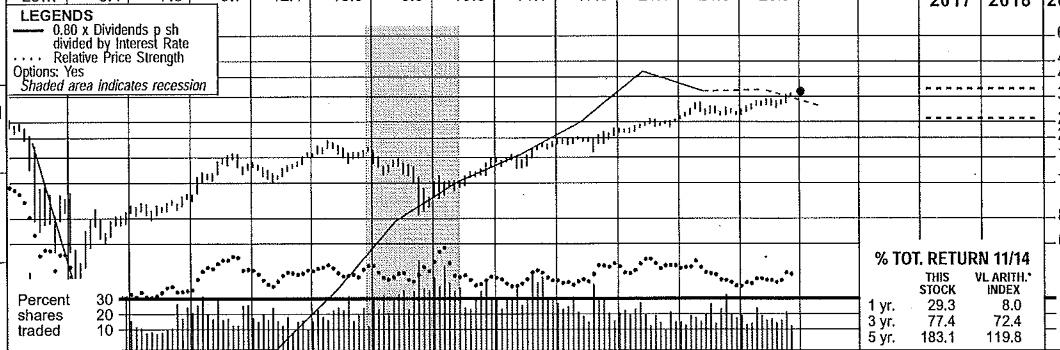
RECENT PRICE 34.01 | P/E RATIO 20.6 (Trailing: 19.3 Median: 14.0) | RELATIVE P/E RATIO 1.11 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 Lowered 12/5/14
SAFETY 2 Raised 3/21/14
TECHNICAL 4 Lowered 11/14/14
BETA .70 (1.00 = Market)

High:	10.7	10.6	16.8	17.0	19.5	17.5	16.1	19.3	22.4	25.0	30.0	34.1
Low:	3.4	7.8	9.7	12.1	15.0	8.3	10.0	14.1	17.0	21.1	24.6	26.0

Target Price Range 2017 | 2018 | 2019

LEGENDS
— 0.80 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+5%)	4%
Low	25	(-25%)	-3%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	2	1	1	0	0	0	4	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	193	177	174
to Sell	177	187	196
Hld's(000)	237528	234703	237560

Percent shares traded 30 / 20 / 10

% TOT. RETURN 11/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	29.3	8.0
3 yr.	77.4	72.4
5 yr.	183.1	119.8

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
47.56	52.59	74.24	72.16	60.28	34.21	28.06	28.52	30.57	28.95	30.13	27.23	25.77	25.59	23.90	24.68	*26.20*	*25.25*	Revenues per sh	*27.50*
6.60	7.87	7.61	5.24	d.09	2.39	2.87	3.43	3.22	3.08	3.88	3.47	3.70	3.65	3.82	4.06	*4.20*	*4.45*	"Cash Flow" per sh	*5.25*
2.24	2.85	2.53	1.27	d2.99	d.29	.74	1.10	.64	.64	1.23	.93	1.33	1.45	1.53	1.66	*1.75*	*1.85*	Earnings per sh A	*2.25*
1.26	1.39	1.46	1.46	1.09	--	--	--	--	.20	.36	.50	.66	.84	.96	1.02	*1.08*	*1.14*	Div'd Decl'd per sh B ■	*1.35*
11.98	9.69	8.51	9.49	5.18	3.32	2.69	2.69	3.01	5.61	3.50	3.59	3.29	3.47	4.65	4.98	*6.05*	*5.55*	Cap'l Spending per sh	*5.25*
20.63	21.17	19.48	14.21	7.86	9.84	10.63	10.53	10.03	9.46	10.88	11.42	11.19	11.92	12.09	12.98	*13.40*	*14.25*	Book Value per sh C	*17.25*
108.11	116.04	121.20	132.99	144.10	161.13	195.00	220.50	222.78	225.15	226.41	227.89	249.60	254.10	264.10	266.10	*275.00*	*277.00*	Common Shs Outst'g D	*283.00*
19.9	13.9	9.6	20.8	--	--	12.4	12.6	22.2	26.8	10.9	13.6	12.5	13.6	15.1	16.3	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
1.03	.79	.62	1.07	--	--	.66	.67	1.20	1.42	.66	.91	.80	.85	.96	.92	*Value Line*		Relative P/E Ratio	*.85*
2.8%	3.5%	6.0%	5.5%	7.5%	--	--	--	--	1.2%	2.7%	4.0%	4.0%	4.3%	4.2%	3.8%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $8861 mill. Due in 5 Yrs $2985 mill.
LT Debt $8171 mill. LT Interest $420 mill.
Incl. $129 mill. capitalized leases.
(LT interest earned: 2.9x)
Leases, Uncapitalized Annual rentals $26 mill.
Pension Assets-12/13 $1964 mill. Oblig. $2073 mill.
Pfd Stock $37 mill. Pfd Div'd $2 mill.
Incl. 373,148 shs. $4.50 $100 par, cum., callable at $110.00.
Common Stock 275,100,000 shs.

MARKET CAP: $9.4 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
5472.0	6288.0	6810.0	6519.0	6821.0	6205.0	6432.0	6503.0	6312.0	6566.0	*7200*	*7000*	Revenues ($mill)	*7800*
144.0	247.0	158.0	168.0	300.0	231.0	356.0	384.0	413.0	454.0	*485*	*525*	Net Profit ($mill)	*665*
18.6%	25.6%	--	37.6%	31.6%	34.6%	38.1%	36.8%	39.4%	39.9%	*39.5%*	*39.5%*	Income Tax Rate	*39.5%*
--	15.4%	6.3%	3.6%	1.3%	13.0%	2.2%	2.6%	2.9%	2.0%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
75.3%	73.5%	71.7%	70.5%	69.4%	67.9%	70.1%	66.9%	67.9%	67.5%	*68.5%*	*67.5%*	Long-Term Debt Ratio	*62.5%*
21.5%	23.4%	24.9%	25.9%	27.4%	29.0%	29.5%	32.6%	31.6%	32.2%	*31.0%*	*32.5%*	Common Equity Ratio	*37.0%*
9640.0	9913.0	8961.0	8212.0	8993.0	8977.0	9473.0	9279.0	10101	10730	*11925*	*12175*	Total Capital ($mill)	*13100*
8636.0	7845.0	7976.0	8728.0	9190.0	9682.0	10069	10633	11551	12246	*13225*	*14050*	Net Plant ($mill)	*16100*
4.4%	5.0%	4.5%	4.5%	5.4%	4.7%	5.8%	6.3%	5.9%	6.0%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.5%*
6.1%	9.4%	6.2%	6.9%	10.9%	8.0%	12.5%	12.5%	12.8%	13.0%	*13.0%*	*13.0%*	Return on Shr. Equity	*13.5%*
6.2%	9.9%	6.4%	7.2%	11.7%	8.5%	12.5%	12.6%	12.9%	13.1%	*13.0%*	*13.5%*	Return on Com Equity E	*13.5%*
6.2%	9.9%	6.4%	5.1%	8.4%	4.1%	6.9%	5.6%	5.0%	5.2%	*5.0%*	*5.5%*	Retained to Com Eq	*6.0%*
11%	6%	10%	35%	31%	54%	46%	55%	61%	60%	*60%*	*60%*	All Div'ds to Net Prof	*58%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+.4	+.6	-3.1
Avg. Indust. Use (MWH)	1086	1113	1000
Avg. Indust. Revs. per KWH (¢)	8.21	8.06	8.93
Capacity at Peak (Mw)	8588	8607	8603
Peak Load, Summer (Mw)	8930	9006	8509
Annual Load Factor (%)	50.8	48.7	52.5
% Change Customers (yr-end)	-.1	--	+.1
Fixed Charge Cov. (%)	237	268	282

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-8.0%	-3.5%	*2.0%*
"Cash Flow"	4.5%	2.5%	*5.5%*
Earnings	--	13.0%	*6.5%*
Dividends	1.0%	NMF	*6.0%*
Book Value	1.5%	4.0%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	2055	1364	1464	1620	6503.0
2012	1802	1333	1507	1670	6312.0
2013	1979	1406	1445	1736	6566.0
2014	2523	1468	1430	*1779*	*7200*
2015	*2200*	*1500*	*1500*	*1800*	*7000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.51	.26	.53	.15	1.45
2012	.36	.37	.55	.25	1.53
2013	.53	.29	.46	.37	1.66
2014	.75	.30	.34	*.36*	*1.75*
2015	*.55*	*.40*	*.55*	*.35*	*1.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec. 31	Full Year
2010	.15	.15	.15	.21	.66
2011	.21	.21	.21	.21	.84
2012	.24	.24	.24	.24	.96
2013	.255	.255	.255	.255	1.02
2014	.27	.27	.27	.27	

BUSINESS: CMS Energy Corporation is a holding company for Consumers Energy, which supplies electricity and gas to lower Michigan (excluding Detroit). Has 1.8 million electric, 1.7 million gas customers. Has 1,034 megawatts of nonregulated generating capacity. Sold Palisades nuclear plant in '07. Electric revenue breakdown: residential, 44%; commercial, 31%; industrial, 18%; other, 7%. Generating sources: coal, 46%; gas, '4%; other, 2%; purchased, 48%. Fuel costs: 51% of revenues. '13 reported deprec. rates: 3.5% electric, 2.8% gas, 7.0% other. Has 7,500 employees. Chairman: David W. Joos. President & CEO: John G. Russell. Incorporated: Michigan. Address: One Energy Plaza, Jackson, Michigan 49201. Tel.: 517-788-0550. Internet: www.cmsenergy.com.

CMS Energy's utility subsidiary has a gas rate case pending. Consumers Energy is seeking a tariff increase of $88 million, based on a 10.7% return on equity. The utility is also seeking regulatory mechanisms that would recover certain expenditures currently (instead of having to wait to file a general rate case) and decouple revenues from volume. The staff of the Michigan Public Service Commission (MPSC) is recommending a boost of just $15 million, based on a 10% ROE. Under state regulatory law, Consumers will self-implement an interim rate hike in early 2015. The MPSC's order is due in mid-2015.

Consumers is buying a gas-fired generating plant. The utility has agreed to pay $155 million for a 540-megawatt facility. The purchase is scheduled for completion in late 2015. This will help offset the loss of capacity when Consumers retires 950 coal-fired megawatts in April of 2016.

Consumers has filed an electric rate application. The utility is seeking a hike of $163 million, based on a 10.7% ROE. Consumers would self-implement an interim rate hike in mid-2015, and the MPSC's decision would be due in late 2015, to coincide with the completion of the acquisition of the aforementioned gas-fired plant.

We expect steady earnings growth in 2014 and 2015. Rate relief, modest demand growth, and effective cost controls are benefiting the company. Note that our 2014 estimate of $1.75 is a bit below the company's typically narrow earnings guidance of $1.76-$1.78 a share because CMS Energy is *excluding* a $0.03-a-share charge that we have included in our presentation. The company has established a goal of 5%-7% annual profit growth, and we think CMS Energy will reach this objective this year and next.

We estimate that the board of directors will raise the quarterly dividend in early 2015. We forecast a hike of $0.015 a share (5.6%) quarterly, the same increase as in each of the past two years.

CMS Energy stock has a dividend yield that is average for a utility. Like many utility issues, the recent price is near the upper end of our 2017-2019 Target Price Range. Accordingly, total return potential is minimal.

Paul E. Debbas, CFA *December 19, 2014*

(A) Diluted EPS. Excl. nonrec. gains (losses): '05, ($1.61); '06, ($1.08); '07, ($1.26); '09, (7¢); '10, 3¢; '11, 12¢; '12, (14¢); gains (losses) on disc. ops.: '05, 7¢; '06, 3¢; '07, (40¢); '09, 8¢; '10, (8¢); '11, 1¢; '12, 3¢. '13 EPS don't add due to rounding. Next earnings report due late Jan. (B) Div'ds historically paid late Feb., May, Aug., & Nov. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '13: $5.75/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '13: 10.3%; earned on avg. com. eq., '13: 13.2%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	70

CON. EDISON NYSE-ED

RECENT PRICE 63.46 | P/E RATIO 16.4 (Trailing: 15.3; Median: 15.0) | RELATIVE P/E RATIO 0.90 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Raised 11/15/13
SAFETY 1 New 7/27/90
TECHNICAL 3 Lowered 11/7/14
BETA .60 (1.00 = Market)

High:	46.0	45.6	49.3	49.3	52.9	49.3	46.3	51.0	62.7	66.0	64.0	64.7
Low:	36.6	37.2	41.1	41.2	43.1	34.1	32.6	41.5	48.6	53.6	54.2	52.2

Target Price Range 2017 | 2018 | 2019

2017-19 PROJECTIONS

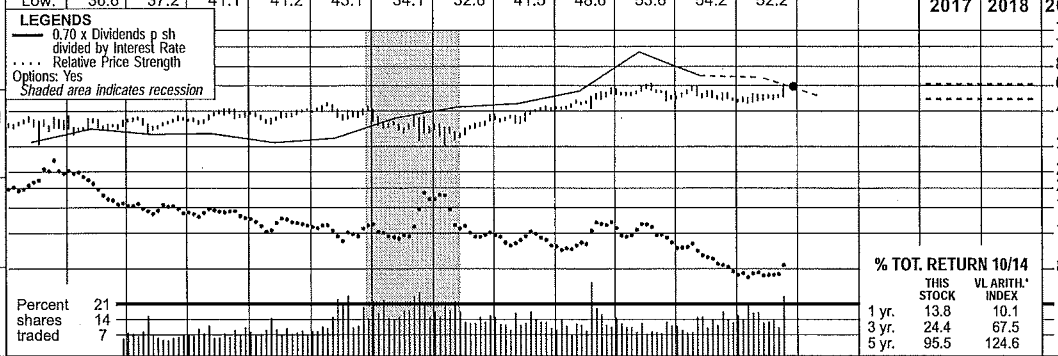
	Price	Gain	Ann'l Total Return
High	65	(Nil)	5%
Low	55	(-15%)	1%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	1	0	0	1	0	0	1	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2013	1Q2014	2Q2014
to Buy	258	309	306
to Sell	283	249	262
Hld's(000)	137375	141570	144306



% TOT. RETURN 10/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.8	10.1
3 yr.	24.4	67.5
5 yr.	95.5	124.6

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
30.46	35.04	44.48	45.41	39.65	43.51	40.24	47.66	47.14	48.23	49.62	46.36	45.69	44.17	41.62	42.27	44.35	44.70	Revenues per sh	49.25
5.29	5.74	5.51	5.70	5.44	5.12	4.54	5.27	5.28	5.77	5.99	5.86	6.24	6.61	7.15	7.45	7.65	8.00	"Cash Flow" per sh	9.00
3.04	3.13	2.74	3.21	3.13	2.83	2.32	2.99	2.95	3.48	3.36	3.14	3.47	3.57	3.86	3.93	3.90	3.95	Earnings per sh A	4.25
2.12	2.14	2.18	2.20	2.22	2.24	2.26	2.28	2.30	2.32	2.34	2.36	2.38	2.40	2.42	2.46	2.52	2.58	Div'd Decl'd per sh B ■	2.75
2.66	3.17	4.52	5.20	5.68	5.72	5.60	6.59	7.17	7.09	8.50	7.80	6.96	6.72	7.06	8.67	9.70	10.25	Cap'l Spending per sh	9.50
25.88	25.31	25.81	26.71	27.68	28.44	29.09	29.80	31.09	32.58	35.43	36.46	37.93	39.05	40.53	41.81	43.25	44.70	Book Value per sh C	49.25
232.83	213.81	212.03	212.15	213.93	225.84	242.51	245.29	257.46	272.02	273.72	281.12	291.62	292.89	292.87	292.87	293.00	293.00	Common Shs Outst'g D	293.00
15.3	14.0	12.0	12.0	13.3	14.3	18.2	15.1	15.5	13.8	12.3	12.5	13.3	15.1	15.4	14.7	Bold figures are		Avg Ann'l P/E Ratio	14.0
.80	.80	.78	.61	.73	.82	.96	.80	.84	.73	.74	.83	.85	.95	.98	.83	Value Line		Relative P/E Ratio	.90
4.6%	4.9%	6.6%	5.7%	5.3%	5.5%	5.3%	5.0%	5.0%	4.8%	5.7%	6.0%	5.2%	4.5%	4.1%	4.3%	estimates		Avg Ann'l Div'd Yield	4.6%

CAPITAL STRUCTURE as of 6/30/14
Total Debt $12660 mill. **Due in 5 Yrs** $4530 mill.
LT Debt $11084 mill. **LT Interest** $543 mill.
(LT interest earned: 4.2x)

Leases, Uncapitalized Annual rentals $17 mill.

Pension Assets-12/13 $10755 mill. **Oblig.** $12197 mill.

Pfd Stock None

Common Stock 292,885,004 shs. as of 7/31/14
MARKET CAP: $19 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
9758.0	11690	12137	13120	13583	13032	13325	12938	12188	12381	13000	13100	Revenues ($mill)	14450
560.0	719.0	749.0	936.0	933.0	868.0	992.0	1062.0	1141.0	1157.0	1145	1170	Net Profit ($mill)	1265
34.3%	33.6%	35.2%	32.6%	36.0%	34.2%	36.0%	36.1%	34.5%	31.8%	34.0%	34.0%	Income Tax Rate	34.0%
7.7%	2.2%	1.6%	1.9%	1.7%	2.6%	2.4%	1.6%	.5%	.5%	1.0%	1.0%	AFUDC % to Net Profit	1.0%
47.4%	49.6%	50.2%	45.6%	48.3%	48.5%	48.6%	46.5%	45.9%	46.1%	48.0%	48.0%	Long-Term Debt Ratio	49.0%
51.0%	49.0%	48.5%	53.1%	50.6%	50.4%	50.4%	52.5%	54.1%	53.9%	52.0%	52.0%	Common Equity Ratio	51.0%
13828	14921	16515	16687	19160	20330	21952	21794	21933	22735	24425	25125	Total Capital ($mill)	28200
16106	17112	18445	19914	20874	22464	23863	25093	26939	28436	30175	32000	Net Plant ($mill)	36300
5.6%	6.3%	6.0%	7.0%	6.2%	5.7%	5.9%	6.2%	6.5%	6.4%	6.0%	6.0%	Return on Total Cap'l	5.5%
7.7%	9.6%	9.1%	10.3%	9.4%	8.3%	8.8%	9.1%	9.6%	9.4%	9.0%	9.0%	Return on Shr. Equity	9.0%
7.8%	9.7%	9.2%	10.4%	9.5%	8.4%	8.9%	9.2%	9.6%	9.4%	9.0%	9.0%	Return on Com Equity E	9.0%
.8%	2.6%	2.6%	3.9%	3.1%	2.5%	3.2%	3.1%	3.6%	3.6%	3.0%	3.0%	Retained to Com Eq	3.0%
89%	74%	73%	63%	67%	71%	65%	66%	62%	62%	64%	64%	All Div'ds to Net Prof	64%

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-1.4	-1.1	+.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	14788	14344	14883
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	360	382	385

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	--	-2.5%	2.5%
"Cash Flow"	2.5%	4.5%	4.0%
Earnings	2.0%	3.0%	2.0%
Dividends	1.0%	1.0%	2.0%
Book Value	4.0%	4.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	3349	2993	3629	2967	12938
2012	3078	2771	3438	2901	12188
2013	3306	2767	3440	2868	12381
2014	3789	2911	3390	2910	13000
2015	3650	2950	3500	3000	13100

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	1.06	.56	1.30	.65	3.57
2012	.94	.73	1.49	.70	3.86
2013	1.16	.49	1.49	.79	3.93
2014	1.23	.64	1.49	.54	3.90
2015	1.20	.65	1.50	.60	3.95

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.595	.595	.595	.595	2.38
2011	.60	.60	.60	.60	2.40
2012	.605	.605	.605	.605	2.42
2013	.615	.615	.615	.615	2.46
2014	.63	.63	.63		

BUSINESS: Consolidated Edison, Inc. is a holding company for Consolidated Edison Company of New York, Inc. (CECONY), which sells electricity, gas, and steam in most of New York City and Westchester County. Also owns Orange and Rockland Utilities (O&R, acquired 7/99), which operates in New York, New Jersey, and Pennsylvania. Has 3.6 million electric, 1.2 million gas customers. Pursues competitive energy opportunities through three wholly owned subsidiaries. Purchases most of its power. Fuel costs: 33% of revenues. '13 reported depreciation rates: 2.8%-3.2%. Has 14,600 employees. Chairman, President & CEO: John McAvoy. Inc.: New York. Address: 4 Irving Place, New York, New York 10003. Tel.: 212-460-4600. Internet: www.conedison.com.

We have raised our 2014 earnings estimate for Consolidated Edison by $0.05 a share. Third-quarter profits were greater than we expected. There have been some positive and some negative factors affecting the bottom line. Rate relief is a plus. The utility is also benefiting from conversions of heating customers from oil to natural gas. The nonregulated operations are faring well. Pension expense is down. On the other hand, other operating and maintenance costs are rising, including healthcare costs. Our revised estimate is at the upper end of the company's earnings guidance of $3.80-$3.90 a share, which is close to what the company earned in 2013. The stock is ranked 3 (Average) for Timeliness.

We are sticking with our 2015 profit forecast of $3.95 a share. Oil-to-gas conversions should continue to benefit the company. ConEd has not yet given earnings guidance for 2015.

We expect a dividend increase at the board meeting in early 2015. ConEd has a 40-year track record of hikes in the disbursement. We estimate that the directors will raise the quarterly payout by $0.015 a share (2.4%), the same increase as in 2014.

Finances are sound. The common equity ratio and fixed-charge coverage are very healthy. The company's size is another plus. ConEd merits a Financial Strength rating of A+.

There is a concern that investors need to keep in mind. In March of 2014, an explosion in Manhattan killed eight people and injured dozens more. Various investigations are pending. About 20 lawsuits have been filed against ConEd. The company believes that its insurance is adequate. It has not taken a reserve for a potential liability from the incident.

ConEd stock has a dividend yield that is about half a percentage point above the utility average. Conservative income-oriented investors might also like the equity's top rank for Safety. However, with the recent price near the upper end of our 2017-2019 Target Price Range, total return potential is unexciting. So far, the uncertainty about the explosion does not appear to have hurt the stock, which is up 15% year to date.

Paul E. Debbas, CFA *November 21, 2014*

(A) Diluted EPS. Excl. nonrec. gain (losses): '02, (11¢); '03, (45¢); '13, (32¢); '14, 9¢; gain on discontinued operations: '08, $1.01. Next earnings report due early Feb. (B) Div'ds historically paid in mid-Mar., June, Sept., and Dec. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '13: $26.83/sh. (D) In millions. (E) Rate base: net orig. cost. Rate allowed on com. eq. for CECONY in '14: 9.2% elec., 9.3% gas and steam; O&R in '12 (elec.) 9.4%, in '09 (gas) 10.3%; earned on avg. com. eq., '13: 9.5%. Regulatory Climate: Below Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	85

DOMINION RES. NYSE-D

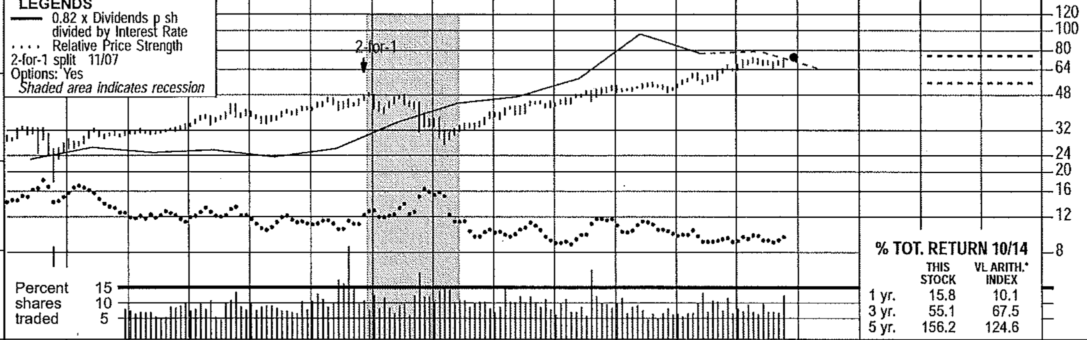
RECENT PRICE	P/E RATIO	(Trailing: 22.3 / Median: 17.0)	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
73.91	21.3	Trailing: 22.3; Median: 17.0	1.17	3.4%	

TIMELINESS 3 Raised 11/15/13
SAFETY 2 Raised 9/11/98
TECHNICAL 4 Lowered 11/21/14
BETA .70 (1.00 = Market)

High:	33.0	34.4	43.5	42.2	49.4	48.5	39.8	45.1	53.6	55.6	68.0	74.6
Low:	25.9	30.4	33.3	34.4	39.8	31.3	27.1	36.1	42.1	48.9	51.9	63.1

Target Price Range
2017 | 2018 | 2019

LEGENDS
—— 0.82 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 11/07
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(Nil)	4%
Low	55	(-25%)	-3%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	1	0	0	5	0	0	1
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	1	0	0

Institutional Decisions

	4Q2013	1Q2014	2Q2014
to Buy	339	350	353
to Sell	372	377	391
Hld's(000)	348186	345498	344597

% TOT. RETURN 10/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	15.8	10.1
3 yr.	55.1	67.5
5 yr.	156.2	124.6

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
15.65	14.81	18.84	19.94	16.58	18.57	20.54	25.96	23.61	27.17	27.93	25.24	26.17	25.24	22.73	22.56	*21.10*	*20.80*	Revenues per sh	*19.75*
2.99	3.68	3.71	3.92	4.45	3.97	4.18	3.70	4.91	5.08	5.07	4.82	5.11	5.04	5.24	5.47	*6.10*	*6.45*	"Cash Flow" per sh	*7.00*
.86	1.50	1.25	1.49	2.41	1.96	2.13	1.50	2.40	2.13	3.04	2.64	2.89	2.76	2.75	3.09	*3.40*	*3.65*	Earnings per sh A	*4.00*
1.29	1.29	1.29	1.29	1.29	1.29	1.30	1.34	1.38	1.46	1.58	1.75	1.83	1.97	2.11	2.25	*2.40*	*2.50*	Div'd Decl'd per sh B ■	*2.80*
1.60	2.16	2.82	2.31	2.17	5.20	3.88	4.83	5.81	6.89	6.09	6.40	5.89	6.41	7.20	7.06	*9.55*	*7.95*	Cap'l Spending per sh	*6.25*
13.67	12.75	14.22	15.81	16.57	16.20	16.79	14.96	18.50	16.31	17.28	18.66	20.66	20.09	18.34	20.02	*20.45*	*21.75*	Book Value per sh C	*28.00*
388.92	372.64	491.60	529.40	616.20	650.40	680.40	695.00	698.00	576.80	583.20	599.40	580.80	569.70	576.10	581.50	*583.00*	*584.00*	Common Shs Outst'g D	*636.00*
24.6	14.5	19.4	20.9	12.0	15.2	15.1	24.9	16.0	20.6	13.8	12.7	14.3	17.3	18.9	19.2	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
1.28	.83	1.26	1.07	.66	.87	.80	1.33	.86	1.09	.83	.85	.91	1.09	1.20	1.08	*Value Line*		Relative P/E Ratio	*1.00*
6.1%	5.9%	5.3%	4.1%	4.4%	4.3%	4.0%	3.6%	3.6%	3.3%	3.8%	5.2%	4.4%	4.1%	4.1%	3.8%	*estimates*		Avg Ann'l Div'd Yield	*4.4%*

CAPITAL STRUCTURE as of 6/30/14
Total Debt $24418 mill. **Due in 5 Yrs** $10058 mill.
LT Debt $20473 mill. **LT Interest** $972 mill.
(LT interest earned: 4.1x)

Leases, Uncapitalized Annual rentals $63 mill.
Pension Assets-12/13 $6113 mill. **Oblig.** $5625 mill.
Pfd Stock $134 mill. **Pfd Div'd** $8 mill.
1,340,140 shs. $4.04-$7.05, $100 liq. pref., redeemable at $101.00-$112.50/sh. Called in 3Q of '14.
Common Stock 582,667,882 shs.

MARKET CAP: $43 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
13972	18041	16482	15674	16290	15131	15197	14379	13093	13120	*12300*	*12150*	Revenues ($mill)	*12600*
1425.0	1050.0	1704.0	1414.0	1781.0	1585.0	1724.0	1603.0	1594.0	1806.0	*1995*	*2145*	Net Profit ($mill)	*2570*
35.4%	35.7%	35.5%	33.4%	37.1%	33.2%	38.6%	34.6%	36.2%	33.0%	*32.0%*	*32.5%*	Income Tax Rate	*32.5%*
4.9%	9.7%	7.9%	7.3%	4.9%	4.8%	5.9%	5.3%	5.7%	3.7%	*6.0%*	*6.0%*	AFUDC % to Net Profit	*4.0%*
57.0%	57.9%	52.9%	57.8%	59.1%	57.5%	56.3%	59.8%	60.9%	61.9%	*64.5%*	*63.0%*	Long-Term Debt Ratio	*58.0%*
42.0%	41.1%	46.2%	41.1%	39.8%	41.5%	42.8%	39.3%	38.2%	37.3%	*35.5%*	*37.0%*	Common Equity Ratio	*42.0%*
27190	25307	27961	22898	25290	26923	28012	29097	27676	31229	*33650*	*34300*	Total Capital ($mill)	*42500*
26716	28940	29382	21352	23274	25592	26713	29670	30773	32628	*36625*	*39625*	Net Plant ($mill)	*46500*
6.9%	6.1%	7.9%	8.0%	8.7%	7.5%	7.7%	7.0%	7.5%	7.3%	*7.5%*	*7.5%*	Return on Total Cap'l	*7.5%*
12.2%	9.9%	12.9%	14.6%	17.2%	13.9%	14.1%	13.7%	14.7%	15.2%	*16.5%*	*17.0%*	Return on Shr. Equity	*14.5%*
12.3%	9.9%	13.1%	14.9%	17.5%	14.0%	14.2%	13.9%	14.9%	15.4%	*16.5%*	*17.0%*	Return on Com Equity E	*14.5%*
4.8%	1.1%	5.6%	5.0%	8.4%	4.7%	5.3%	4.0%	3.5%	4.2%	*5.0%*	*5.5%*	Retained to Com Eq	*4.5%*
62%	89%	58%	67%	52%	67%	63%	71%	77%	73%	*71%*	*68%*	All Div'ds to Net Prof	*69%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-3.4	-2.3	+2.7
Avg. Indust. Use (MWH)	14823	15241	14444
Avg. Indust. Revs. per KWH (¢)	5.95	6.13	6.00
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	+.9	+.9
Fixed Charge Cov. (%)	318	316	339

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	2.5%	-2.0%	*-3.0%*
"Cash Flow"	2.5%	1.0%	*5.0%*
Earnings	4.0%	2.5%	*5.5%*
Dividends	5.0%	7.5%	*5.0%*
Book Value	2.0%	2.5%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	4057	3341	3803	3178	14379
2012	3462	3053	3411	3167	13093
2013	3523	2980	3432	3185	13120
2014	3630	2813	3050	*2807*	*12300*
2015	*3350*	*2800*	*3100*	*2900*	*12150*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.89	.58	.69	.60	2.76
2012	.86	.48	.80	.61	2.75
2013	.86	.47	1.02	.74	3.09
2014	1.03	.60	.95	*.82*	*3.40*
2015	*1.00*	*.70*	*1.05*	*.90*	*3.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.4575	.4575	.4575	.4575	1.83
2011	.4925	.4925	.4925	.4925	1.97
2012	.5275	.5275	.5275	.5275	2.11
2013	.5625	.5625	.5625	.5625	2.25
2014	.60	.60	.60		

BUSINESS: Dominion Resources, Inc. is a holding company for Virginia Power & North Carolina Power, which serve 2.5 mill. customers in Virginia & northeastern North Carolina. Acq'd Consolidated Natural Gas (1.3 mill. customers in Ohio & West Virginia) 1/00. Nonutility operations include independent power production. Owns 68.5% of Dominion Midstream Partners. Elec. rev. breakdown: residential, 46%; commercial, 33%; industrial, 7%; other, 14%. Generating sources: nuclear, 33%; coal, 29%; gas, 16%; other, 1%; purch., 21%. Fuel costs: 41% of revs. '13 reported depr. rates: 2.4%-3.8%. Has 14,500 employees. Chairman, Pres. & CEO: Thomas F. Farrell II. Inc.: VA. Address: 120 Tredegar St., P.O. Box 26532, Richmond, VA 23261-6532. Tel.: 804-819-2000. Internet: www.dom.com.

Dominion Resources had an initial public offering for its natural gas master limited partnership in October. Dominion owns 68.5% of the new MLP, Dominion Midstream Partners (NYSE: DM). Dominion Midstream Partners has a preferred equity interest in the Cove Point liquefied natural gas facility, which is being converted from an import to an export terminal. This project is expected to be completed in late 2017 at a cost of $3.4 billion-$3.8 billion. The IPO raised nearly $400 million, which Dominion will use to fund construction of Cove Point. The units have fared very well in their brief history, having soared more than 60% from their IPO price.

Virginia Power is building gas-fired generating plants and expanding its transmission system. A 1,329-megawatt plant should begin commercial operation by yearend at a cost of $1.1 billion. A 1,358-mw facility is scheduled for completion in mid-2016 at a cost of $1.3 billion. The utility is earning a return on these investments through riders on customers' bills. Virginia Power also plans to ask the state commission for a certificate of need to build another gas-fired plant, which would begin operating in 2019. As for transmission, the company expects to place $900 million of assets in service in 2014, and is targeting spending of $3.2 billion through 2018. These investments are one reason why we expect higher profits this year and next. All of this capital spending requires financing, most of which has come this year in the form of mandatory convertibles or straight debt.

Dominion has numerous investment opportunities in midstream gas. The most notable is a 45% stake in a proposed $4.5 billion-$5.0 billion pipeline to transport gas from West Virginia to Virginia and North Carolina. A $500 million project in West Virginia would increase access to gas that would supply this pipeline. These projects are expected to be in service in November of 2018.

The dividend yield of Dominion Resources stock is about equal to the utility mean. With the recent price near the upper end of our 2017-2019 Target Price Range, total return potential is minimal.

Paul E. Debbas, CFA *November 21, 2014*

(A) Diluted earnings. Excl. nonrec. gains (losses): '01, (42¢); '03, ($1.46); '04, (22¢); '06, (18¢); '07, $1.67; '08, 12¢; '09, (47¢); '10, $2.18; '11, (7¢); '12, ($1.70); '14, (76¢); losses from disc. ops.: '06, 26¢; '07, 1¢; '10, 26¢; '12, 4¢; '13, 16¢. Next egs. report due late Jan. (B) Div'ds historically paid in mid-Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '13: $8.38/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost, adj. Rate all'd on com. eq. in '11: 10.9%; earned on avg. com. eq., '13: 16.0%. Regul. Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	75

DTE ENERGY CO. NYSE-DTE

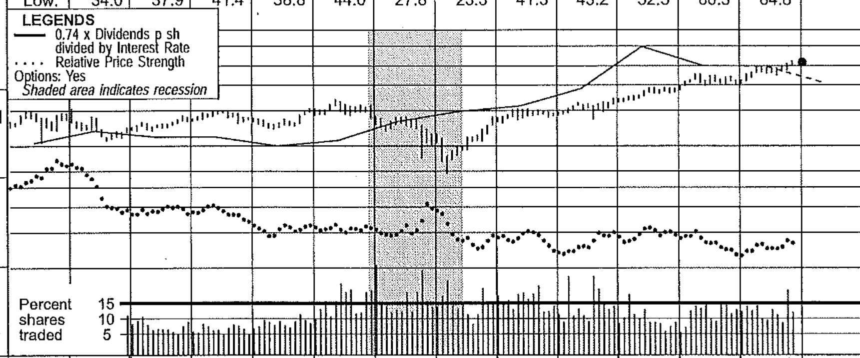
RECENT PRICE 83.31 | P/E RATIO 19.3 (Trailing: 20.2 Median: 15.0) | RELATIVE P/E RATIO 1.04 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 Lowered 11/7/14
SAFETY 2 Raised 12/21/12
TECHNICAL 4 Raised 12/19/14
BETA .75 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
High:	49.5	45.5	48.3	49.2	54.7	45.3	45.0	49.1	55.3	62.6	73.3	84.4
Low:	34.0	37.9	41.4	38.8	44.0	27.8	23.3	41.3	43.2	52.5	60.3	64.8

Target Price Range 2017 | 2018 | 2019

LEGENDS
— 0.74 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(Nil)	4%
Low	60	(-30%)	-3%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	2	0	1	1	0	0	2	0
to Sell	0	4	2	1	2	0	0	4	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	206	204	177
to Sell	208	191	204
Hld's(000)	110596	114784	113691

Percent shares traded 15 10 5

% TOT. RETURN 11/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	26.6	8.0
3 yr.	74.1	72.4
5 yr.	151.2	119.8

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
29.10	32.60	39.24	48.71	40.30	41.76	40.84	50.74	50.93	54.28	57.23	48.45	50.51	52.57	51.01	54.56	67.80	62.45	Revenues per sh	67.50
7.61	8.40	8.59	6.98	8.31	6.95	6.81	8.14	8.19	8.48	8.26	9.38	9.78	9.57	9.77	10.13	11.20	11.60	"Cash Flow" per sh	13.25
3.05	3.33	3.27	2.15	3.83	2.85	2.55	3.27	2.45	2.66	2.73	3.24	3.74	3.67	3.88	3.76	4.45	4.55	Earnings per sh A	5.25
2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.08	2.12	2.12	2.12	2.18	2.32	2.42	2.59	2.69	2.83	Div'd Decl'd per sh B ■	3.30
3.83	5.10	5.25	6.80	5.88	4.45	5.19	5.99	7.92	7.96	8.42	6.26	6.49	8.77	10.56	10.59	12.25	13.80	Cap'l Spending per sh	13.00
25.49	26.95	28.15	28.48	27.26	31.36	31.85	32.44	33.02	35.86	36.77	37.96	39.67	41.41	42.78	44.73	46.50	48.85	Book Value per sh C	55.50
145.07	145.04	142.65	161.13	167.46	168.61	174.21	177.81	177.14	163.23	163.02	165.40	169.43	169.25	172.35	177.09	177.00	180.00	Common Shs Outst'g D	191.00
13.3	11.6	10.3	19.3	11.3	13.7	16.0	13.8	17.4	18.3	14.8	10.4	12.3	13.5	14.9	17.9	Bold figures are		Avg Ann'l P/E Ratio	14.0
.69	.66	.67	.99	.62	.78	.85	.73	.94	.97	.89	.69	.78	.85	.95	1.01	Value Line		Relative P/E Ratio	.90
5.1%	5.3%	6.1%	5.0%	4.8%	5.3%	5.0%	4.6%	4.9%	4.4%	5.2%	6.3%	4.8%	4.7%	4.2%	3.8%	estimates		Avg Ann'l Div'd Yield	4.5%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $8836 mill. Due in 5 Yrs $2919 mill.
LT Debt $7909 mill. LT Interest $395 mill.
Incl. $3 mill. capitalized leases and $480 mill. Trust Preferred Securities.
(LT interest earned: 3.5x)

Leases, Uncapitalized Annual rentals $35 mill.
Pension Assets-12/13 $3720 mill. Oblig. $4380 mill.

Pfd Stock None
Common Stock 176,991,277 shs.

MARKET CAP: $15 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
7114.0	9022.0	9022.0	8861.0	9329.0	8014.0	8557.0	8897.0	8791.0	9661.0	12000	11300	Revenues ($mill)	12900
443.0	576.0	437.0	453.0	445.0	532.0	630.0	624.0	666.0	661.0	795	820	Net Profit ($mill)	1000
27.1%	26.0%	23.9%	25.1%	34.9%	31.6%	32.7%	35.9%	29.8%	27.5%	29.0%	30.0%	Income Tax Rate	30.0%
.7%	1.0%	5.0%	7.1%	11.2%	2.6%	1.6%	1.6%	3.0%	3.5%	5.0%	5.0%	AFUDC % to Net Profit	2.0%
57.8%	55.1%	56.1%	54.4%	56.4%	54.0%	51.3%	50.6%	48.8%	47.7%	50.5%	50.5%	Long-Term Debt Ratio	51.0%
42.2%	44.9%	43.9%	45.6%	43.6%	46.0%	48.7%	49.4%	51.2%	52.3%	49.5%	49.5%	Common Equity Ratio	49.0%
13154	12849	13323	12824	13736	13648	13811	14196	14387	15135	16675	17775	Total Capital ($mill)	21700
10491	10830	11451	11408	12231	12431	12992	13746	14684	15800	16775	17975	Net Plant ($mill)	21100
5.2%	6.3%	5.1%	5.3%	5.0%	5.7%	6.3%	5.9%	6.1%	5.7%	6.0%	6.0%	Return on Total Cap'l	6.0%
8.0%	10.0%	7.5%	7.7%	7.4%	8.5%	9.4%	8.9%	9.0%	8.3%	9.5%	9.0%	Return on Shr. Equity	9.5%
8.0%	10.0%	7.5%	7.7%	7.4%	8.5%	9.4%	8.9%	9.0%	8.3%	9.5%	9.0%	Return on Com Equity E	9.5%
1.6%	3.7%	1.2%	1.5%	1.7%	2.9%	4.0%	3.4%	3.5%	2.7%	4.0%	3.5%	Retained to Com Eq	3.5%
80%	63%	84%	80%	77%	65%	57%	62%	61%	67%	60%	62%	All Div'ds to Net Prof	63%

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+.6	-.5	-.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	11314	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	- -	- -	NA
Fixed Charge Cov. (%)	282	286	271

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	2.0%	-.5%	4.0%
"Cash Flow"	3.0%	3.5%	5.0%
Earnings	2.5%	7.5%	5.5%
Dividends	1.5%	3.0%	5.0%
Book Value	4.0%	4.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	2431	2028	2265	2173	8897.0
2012	2239	2013	2190	2349	8791.0
2013	2516	2225	2387	2533	9661.0
2014	3930	2698	2595	2777	12000
2015	3200	2600	2700	2800	11300

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	1.04	.67	1.07	.89	3.67
2012	.91	.87	1.30	.79	3.88
2013	1.34	.60	1.13	.70	3.76
2014	1.84	.70	.88	1.03	4.45
2015	1.60	.80	1.15	1.00	4.55

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.53	.53	.53	.56	2.15
2011	.56	.56	.5875	.5875	2.30
2012	.5875	.5875	.5875	.62	2.38
2013	.62	.62	.655	.655	2.55
2014	.655	.655	.69	.69	

BUSINESS: DTE Energy Company is a holding company for DTE Electric (formerly Detroit Edison), which supplies electricity in Detroit and a 7,600-square-mile area in southeastern Michigan, and DTE Gas (formerly Michigan Consolidated Gas). Customers: 2.1 mill. electric, 1.3 mill. gas. Acquired MCN Energy 6/01. Has various nonutility operations. Electric revenue breakdown: residential, 46%; commercial, 37%; industrial, 15%; other, 2%. Generating sources: coal, 67%; nuclear, 17%; gas, 1%; purchased, 15%. Fuel costs: 37% of revenues. '13 reported deprec. rates: 3.4% electric, 2.4% gas. Has 9,900 employees. Chairman, President & CEO: Gerard M. Anderson. Inc.: Michigan. Address: One Energy Plaza, Detroit, MI 48226-1279. Tel.: 313-235-4000. Internet: www.dteenergy.com.

DTE Energy's electric utility plans to buy a gas-fired generating plant. DTE Electric would pay $240 million for a 732-megawatt peaking facility. The purchase requires the approval of the Federal Energy Regulatory Commission. The Michigan Public Service Commission will also have a say in a general rate case that DTE Electric plans to file in late 2014. The utility will self-implement a rate hike six months later, and this will enable it to place the new asset in the rate base. The final rate order will come in late 2015. DTE Electric is looking for additional generating capacity, as well.

We have cut our 2014 and 2015 earnings estimates. September-quarter profits were well below our expectation, due in part to $0.14 a share of mark-to-market charges that we *include* in our presentation. Our revised estimate for 2014, which we cut by $0.20 a share, is within DTE's targeted range of $4.42-$4.62 a share. Our previous 2015 forecast of $4.80 a share was apparently too optimistic, so we have cut it to $4.55 a share, which is in line with management's guidance of $4.43-$4.67 for 2015. Even our reduced estimates would still provide respectable year-to-year earnings growth.

There is a good deal of growth potential from the nonutility side of the business. Especially noteworthy is the Gas Storage & Pipelines unit. DTE is looking to invest $700 million-$1 billion in a proposed pipeline project, which would be in service in the fourth quarter of 2017. In all, DTE expects to invest $1.5 billion-$1.9 billion from 2015 through 2019. Other businesses include renewable energy, industrial energy services, and reduced emissions fuel, which should provide the opportunity for a $600 million-$800 million investment over the next five years. All told, DTE believes the nonutility operations can produce profit growth of 10%-15% annually.

DTE Energy stock has a dividend yield that is about equal to the industry average. Although we project solid earnings and dividend growth over the 3- to 5-year period, total return potential is minimal because the recent price is near the upper end of our 2017-2019 Target Price Range.

Paul E. Debbas, CFA *December 19, 2014*

(A) Diluted EPS. Excl. nonrec. gains (losses): '03, (16¢); '05, (2¢); '06, 1¢; '07, $1.96; '08, 50¢; '11, 51¢; gains (losses) on disc. ops.: '03, 40¢; '04, (6¢); '05, (20¢); '06, (2¢); '07, $1.20; '08, 13¢; '12, (33¢). '12 EPS don't add due to rounding. Next earnings report due mid-Feb. (B) Div'ds histor. paid in mid-Jan., Apr., July and Oct. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '13: $29.41/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '11: 10.5% elec.; in '13: 10.5% gas; earned on avg. com. eq., '13: 8.6%. Regul. Clim.: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	100

DUKE ENERGY NYSE-DUK

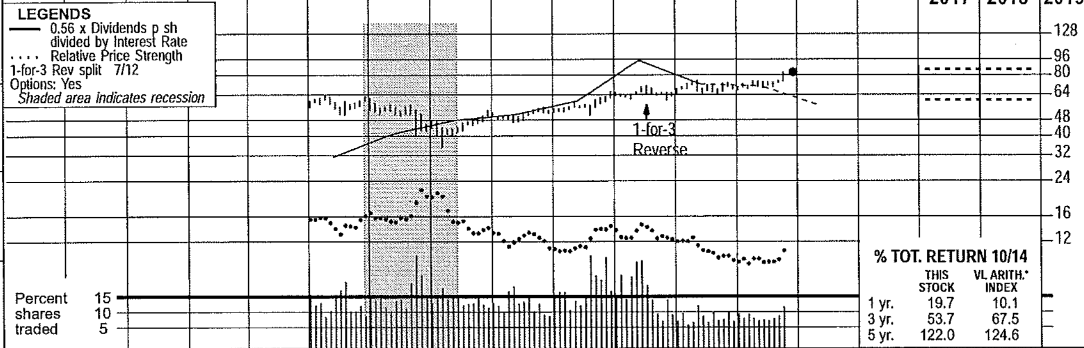
RECENT PRICE	P/E RATIO	(Trailing/Median)	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
82.66	19.6	(Trailing: 20.0 Median: NMF)	1.08	3.9%	

TIMELINESS **3** Lowered 10/24/14
SAFETY **2** New 6/1/07
TECHNICAL **4** Lowered 11/21/14
BETA .60 (1.00 = Market)

	2007	2008	2009	2010	2011	2012	2013	2014
High:	63.9	61.8	53.8	55.8	66.4	71.1	75.5	83.9
Low:	50.7	40.5	35.2	46.4	50.6	59.6	64.2	67.1

Target Price Range 2017 | 2018 | 2019

LEGENDS
— 0.56 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
1-for-3 Rev split 7/12
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+5%)	5%
Low	60	(-25%)	-3%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	9	0	0	0	0	0	1
to Sell	2	2	6	2	1	6	1	1	3

Institutional Decisions

	4Q2013	1Q2014	2Q2014
to Buy	410	435	434
to Sell	458	470	441
Hld's(000)	372545	379686	386233

Percent shares traded 15 10 5

% TOT. RETURN 10/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	19.7	10.1
3 yr.	53.7	67.5
5 yr.	122.0	124.6

Duke Energy Corporation, in its current configuration, began trading on January 3, 2007, the day after it spun off its midstream gas operations into a new company, Spectra Energy (NYSE: SE). Duke Energy shareholders received half a share of Spectra Energy for each Duke share held. In July of 2012, Duke acquired Progress Energy and effected a 1-for-3 reverse split. Data for the "old" Duke are not shown because they are not comparable.

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
--	--	25.32	30.24	31.15	29.18	32.22	32.63	27.88	34.84	***34.10***	***34.90***	Revenues per sh	***39.00***
--	--	7.86	8.11	7.34	7.58	8.49	8.68	6.80	8.56	***8.85***	***9.40***	"Cash Flow" per sh	***10.50***
--	--	2.76	3.60	3.03	3.39	4.02	4.14	3.71	3.98	***4.20***	***4.65***	Earnings per sh A	***5.25***
--	--	--	2.58	2.70	2.82	2.91	2.97	3.03	3.09	***3.15***	***3.21***	Div'd Decl'd per sh B ■	***3.45***
--	--	8.07	7.43	10.35	9.85	10.84	9.80	7.81	7.83	***8.45***	***10.50***	Cap'l Spending per sh	***11.25***
--	--	62.30	50.40	49.51	49.85	50.84	51.14	58.04	58.54	***58.30***	***59.70***	Book Value per sh C	***64.50***
--	--	418.96	420.62	423.96	436.29	442.96	445.29	704.00	706.00	***707.00***	***708.00***	Common Shs Outst'g D	***711.00***
--	--	--	16.1	17.3	13.3	12.7	13.8	17.5	17.4	*Bold figures are*		Avg Ann'l P/E Ratio	***14.0***
--	--	--	.85	1.04	.89	.81	.87	1.11	.98	*Value Line*		Relative P/E Ratio	***.90***
--	--	--	4.4%	5.2%	6.2%	5.7%	5.2%	4.7%	4.4%	*estimates*		Avg Ann'l Div'd Yield	***4.7%***
--	--	10607	12720	13207	12731	14272	14529	19624	24598	***24100***	***24700***	Revenues ($mill)	***27800***
--	--	1080.0	1522.0	1279.0	1461.0	1765.0	1839.0	2136.0	2813.0	***2970***	***3315***	Net Profit ($mill)	***3730***
--	--	29.4%	31.9%	32.5%	34.4%	32.6%	31.3%	30.2%	32.6%	***32.5%***	***34.5%***	Income Tax Rate	***34.5%***
--	--	6.9%	7.2%	16.0%	17.5%	22.7%	23.2%	22.3%	8.8%	***7.0%***	***8.0%***	AFUDC % to Net Profit	***8.0%***
--	--	41.0%	30.9%	38.7%	42.6%	44.3%	45.1%	47.0%	48.0%	***49.5%***	***50.5%***	Long-Term Debt Ratio	***52.5%***
--	--	59.0%	69.1%	61.3%	57.4%	55.7%	54.9%	52.9%	52.0%	***50.5%***	***49.5%***	Common Equity Ratio	***47.5%***
--	--	44220	30697	34238	37863	40457	41451	77307	79482	***81525***	***85025***	Total Capital ($mill)	***96300***
--	--	41447	31110	34036	37950	40344	42661	68558	69490	***70775***	***74875***	Net Plant ($mill)	***88400***
--	--	3.1%	6.0%	4.8%	4.9%	5.5%	5.6%	3.6%	4.6%	***4.5%***	***5.0%***	Return on Total Cap'l	***5.0%***
--	--	4.1%	7.2%	6.1%	6.7%	7.8%	8.1%	5.2%	6.8%	***7.0%***	***8.0%***	Return on Shr. Equity	***8.0%***
--	--	4.1%	7.2%	6.1%	6.7%	7.8%	8.1%	5.2%	6.8%	***7.0%***	***8.0%***	Return on Com Equity E	***8.0%***
--	--	4.1%	2.0%	.6%	1.1%	2.1%	2.2%	.9%	1.5%	***2.0%***	***2.5%***	Retained to Com Eq	***3.0%***
--	--	--	72%	89%	84%	73%	72%	82%	78%	***75%***	***69%***	All Div'ds to Net Prof	***66%***

CAPITAL STRUCTURE as of 9/30/14
Total Debt $41645 mill. **Due in 5 Yrs** $14077 mill.
LT Debt $38702 mill. **LT Interest** $1684 mill.
Incl. $1516 mill. capitalized leases. Incl. $1265 mill. nonrecourse LT debt of variable interest entities.
(LT interest earned: 3.6x)

Leases, Uncapitalized Annual rentals $175 mill.
Pension Assets-12/13 $8142 mill.
Oblig. $7361 mill.
Pfd Stock None
Common Stock 707,290,608 shs.
as of 11/4/14
MARKET CAP: $58 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-2.1	-2.8	+1.3
Avg. Indust. Use (MWH)	3062	2675	2687
Avg. Indust. Revs. per KWH (¢)	4.89	5.84	5.89
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+.3	+.8	+.8
Fixed Charge Cov. (%)	292	263	327

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	--	2.0%	*3.5%*
"Cash Flow"	--	.5%	*4.5%*
Earnings	--	4.5%	*5.0%*
Dividends	--	11.5%	*2.0%*
Book Value	--	.5%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	3663	3534	3964	3368	14529
2012	3630	3577	6722	5695	19624
2013	5898	5879	6709	6112	24598
2014		11971F	6395	***5734***	***24100***
2015	***6000***	***5700***	***6900***	***6100***	***24700***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	1.14	.99	1.35	.66	4.14
2012	.86	.99	1.01	.59	3.71
2013	.89	.74	1.40	.94	3.98
2014		2.08F	1.25	***.87***	***4.20***
2015	***1.20***	***.90***	***1.60***	***.95***	***4.65***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.72	.72	.735	.735	2.91
2011	.735	.735	.75	.75	2.97
2012	.75	.75	.765	.765	3.03
2013	.765	.765	.78	.78	3.09
2014	.78	.78	.795		

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.1 mill. elec. customers in North Carolina, Florida, Indiana, South Carolina, Ohio, & Kentucky, and over 500,000 gas customers in Ohio & Kentucky. Owns independent power plants & has international ops. Acq'd Cinergy 4/06; spun off midstream gas ops. 1/07; acq'd Progress Energy 7/12. Elec. rev. breakdown: residential, 43%; commercial, 31%; industrial, 15%; other, 11%. Generating sources: coal, 36%; nuclear, 29%; gas, 21%; other, 1%; purchased, 13%. Fuel costs: 37% of revs. '13 reported deprec. rates: 2.4%-3.3%. Has 27,900 empls. Chairman: Ann Gray. Pres. & CEO: Lynn J. Good. Inc.: DE. Address: 550 South Tryon St., Charlotte, NC 28202-1803. Tel.: 704-382-3853. Web: www.duke-energy.com.

Duke Energy has reached an agreement to sell its nonregulated generating assets in the Midwest. The company will receive $2.8 billion in cash for its ownership interests in 11 plants and its retail energy marketing business in Ohio. Duke took a $1.23-a-share writedown in the first quarter to reflect an expected loss on the sale, but reversed $0.43 in the third period. (This operation is now treated as discontinued.) The sale is likely to close by the end of the first quarter of 2015. Duke expects the move to be accretive to earnings by 2016. It will use the proceeds for capital spending, to replace debt financing, or to buy back stock.

Duke's regulated utilities plan to buy some power plants. The company has agreed to pay $1.2 billion for another utility's minority stake (about 700 megawatts) in nuclear and coal-fired units in North Carolina that Duke operates. This requires regulatory approval.

The company has other investment opportunities. In South Carolina, Duke is adding 650 mw of gas-fired capacity at a cost of $600 million. In Florida, the utility plans to build a 1,685-mw gas-fired plant at a cost of $1.5 billion. In Indiana, Duke is proposing a seven-year, $1.9 billion plan to modernize its electric grid. Finally, the company has a 40% stake in a proposed $4.5 billion-$5.0 billion pipeline to transport gas from West Virginia to North Carolina.

The aforementioned projects should help produce earnings growth. Note that our earnings presentation *includes* integration costs, which Duke is still incurring, associated with the takeover of Progress Energy in 2012. These expenses reduced earnings by $0.15 a share in the first nine months of 2014.

Duke continues to review its international operations. It expects to complete this in late 2014 or early 2015.

Duke stock is mainly of interest for its dividend yield. The yield is slightly above the utility average. With the recent price near the upper end of our 2017-2019 Target Price Range, total return potential is low. Note that Duke is facing litigation, regulation, and costs associated with the accidental release of coal ash into a river in North Carolina in February of 2014.

Paul E. Debbas, CFA *November 21, 2014*

(A) Dil. EPS. Excl. nonrec. losses: '12, 70¢; '13, 24¢; gains (loss) on disc. ops.: '12, 6¢; '13, 2¢; '14, (81¢). '12 EPS don't add due to chg. in shs., '13 due to rounding. Next egs. report due mid-Feb. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. avail. (C) Incl. intang. In '13: $36.42/sh. (D) In mill., adj. for rev. split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in '13 in NC/SC: 10.2%; in '09 in OH: 10.63% (elec.); in '04 in IN: 10.3%; earned avg. com. eq., '13: 6.8%. Reg. Clim.: NC Avg.; SC, OH, IN Above Avg. (F) Restated 6-month total.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	75

EDISON INTERNAT'L NYSE-EIX

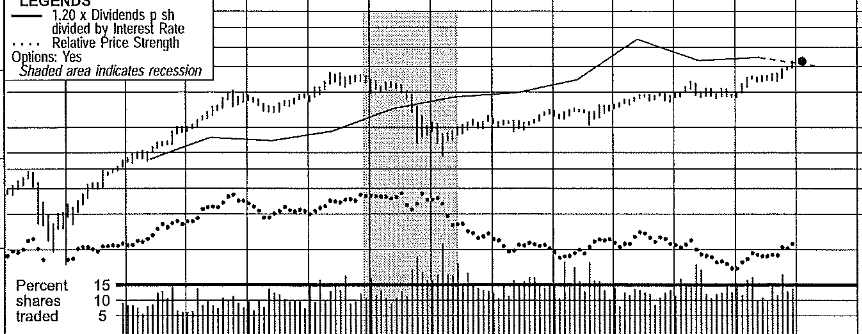
RECENT PRICE 68.17 | P/E RATIO 17.8 (Trailing: 17.0 Median: 12.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 2.5% | VALUE LINE

TIMELINESS 3 Lowered 11/7/14
SAFETY 2 Raised 5/3/13
TECHNICAL 3 Raised 1/2/15
BETA .75 (1.00 = Market)

High:	22.1	32.5	49.2	47.2	60.3	55.7	36.7	39.4	41.6	48.0	54.2	68.7	
Low:	10.6	21.2	30.4	37.9	42.8	26.7	23.1	30.4	32.6	39.6	44.3	44.7	

Target Price Range 2017 | 2018 | 2019

LEGENDS
— 1.20 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+10%)	5%
Low	55	(-20%)	-2%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	1	6	0	3	0	0	1	0	0
to Sell	0	5	0	3	0	0	1	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	219	200	206
to Sell	231	221	217
Hld's(000)	260616	258418	260974

Percent shares traded 15 10 5

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	45.0	6.9
3 yr.	70.7	73.7
5 yr.	117.8	107.3

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
29.12	27.85	35.96	35.10	35.26	37.25	31.30	36.38	38.74	40.25	43.31	37.98	38.09	39.16	36.41	38.61	*40.80*	*42.95*	Revenues per sh	*51.50*
6.65	7.20	d.52	4.35	4.79	5.88	3.79	6.99	7.25	7.60	8.08	7.96	8.41	9.03	9.63	8.80	*9.10*	*9.20*	"Cash Flow" per sh	*11.25*
1.86	2.03	d5.84	1.30	1.82	2.38	.69	3.34	3.28	3.32	3.68	3.24	3.35	3.23	4.55	3.78	*4.00*	*3.75*	Earnings per sh A	*4.50*
1.04	1.08	.83	--	--	--	.80	1.02	1.10	1.18	1.23	1.25	1.27	1.29	1.31	1.37	1.48	*1.71*	Div'd Decl'd per sh B ■	*2.25*
2.75	3.55	4.57	2.86	4.88	3.95	5.32	5.73	7.78	8.67	8.67	10.07	13.94	14.76	12.73	11.05	*12.70*	*13.70*	Cap'l Spending per sh	*13.00*
14.55	15.01	7.43	10.04	13.62	16.52	18.57	20.30	23.66	25.92	29.21	30.20	32.44	30.86	28.95	30.50	*33.35*	*35.30*	Book Value per sh C	*41.50*
350.55	347.21	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	*325.81*	*325.81*	Common Shs Outst'g D	*325.81*
15.1	12.9	--	10.0	7.8	7.0	NMF	11.7	13.0	16.0	12.4	9.7	10.3	11.8	9.7	12.7	*14.1*		Avg Ann'l P/E Ratio	*14.5*
.79	.74	--	.51	.43	.40	NMF	.62	.70	.85	.75	.65	.66	.74	.62	.71	*.75*		Relative P/E Ratio	*.90*
3.7%	4.1%	3.9%	--	--	--	3.1%	2.6%	2.6%	2.2%	2.7%	4.0%	3.7%	3.4%	3.0%	2.8%	2.6%		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $12186 mill. **Due in 5 Yrs** $2809 mill.
LT Debt $10133 mill. **LT Interest** $486 mill.
(LT interest earned: 4.8x)
Leases, Uncapitalized Annual rentals $1349 mill.
Pens. Assets-12/13 $3477 mill. **Oblig.** $4178 mill.
Pfd Stock $2022 mill. **Pfd Div'd** $115 mill.
4,800,198 sh. 4.08%-4.78%, $25 par, call. $25.50-$28.75/sh.; 3,250,000 sh. 5.07%, noncum., call. $100; 1,250,000 sh. 6.5%, cum., $100 liq. value; 350,000 sh. 6.25%, $1000 liq. value; 460,012 sh. 5.1%-5.75%, $2500 liq. value.
Common Stock 325,811,206 shs. **as of 10/24/14**
MARKET CAP: $22 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
10199	11852	12622	13113	14112	12374	12409	12760	11862	12581	*13300*	*14000*	Revenues ($mill)	*16750*
220.0	1132.0	1134.0	1151.0	1266.0	1115.0	1153.0	1112.0	1594.0	1344.0	*1435*	*1365*	Net Profit ($mill)	*1615*
--	26.0%	31.4%	27.3%	30.7%	33.0%	32.1%	25.7%	14.3%	25.2%	*20.0%*	*30.0%*	Income Tax Rate	*30.0%*
11.4%	4.9%	5.1%	8.2%	8.9%	10.5%	16.9%	14.8%	8.5%	7.8%	*8.0%*	*10.0%*	AFUDC % to Net Profit	*7.0%*
60.5%	54.6%	51.3%	49.1%	51.2%	49.3%	51.8%	55.3%	45.2%	45.7%	*44.5%*	*45.0%*	Long-Term Debt Ratio	*44.5%*
37.8%	40.9%	43.5%	46.0%	44.5%	46.5%	44.3%	40.6%	46.2%	46.2%	*47.0%*	*46.5%*	Common Equity Ratio	*48.0%*
15995	16167	17725	18375	21374	21185	23861	24773	20422	21516	*23225*	*24725*	Total Capital ($mill)	*28300*
13475	14469	15913	17403	18969	21966	24778	32116	30273	30455	*32950*	*35675*	Net Plant ($mill)	*43200*
4.2%	9.4%	8.6%	8.3%	7.4%	6.9%	6.3%	6.0%	8.9%	7.3%	*7.0%*	*6.5%*	Return on Total Cap'l	*7.0%*
3.5%	15.4%	13.1%	12.3%	12.1%	10.4%	10.0%	10.0%	14.2%	11.5%	*11.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
3.5%	16.7%	14.0%	13.0%	12.8%	10.8%	10.4%	10.5%	15.9%	12.5%	*12.0%*	*11.0%*	Return on Com Equity E	*11.0%*
NMF	12.2%	10.1%	9.2%	8.6%	6.7%	6.5%	6.3%	11.4%	8.1%	*7.5%*	*6.0%*	Retained to Com Eq	*5.5%*
121%	29%	31%	33%	35%	41%	40%	43%	32%	40%	*41%*	*50%*	All Div'ds to Net Prof	*53%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+.9	+2.6	-.3
Avg. Indust. Use (MWH)	736	763	791
Avg. Indust. Revs. per KWH (¢)	7.09	7.50	8.00
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	22374	21981	22534
Annual Load Factor (%)	50.7	52.7	52.1
% Change Customers (yr-end)	+.4	+.4	+.6
Fixed Charge Cov. (%)	209	308	295

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	.5%	-1.5%	*5.0%*
"Cash Flow"	6.0%	3.5%	*3.5%*
Earnings	7.5%	2.5%	*2.5%*
Dividends	--	2.5%	*9.5%*
Book Value	8.5%	3.0%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	2782	2983	3981	3014	12760
2012	2415	2653	3734	3060	11862
2013	2632	3046	3960	2943	12581
2014	2926	3016	4356	*3002*	*13300*
2015	*3100*	*3400*	*4300*	*3200*	*14000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.62	.54	1.31	.76	3.23
2012	.54	.55	1.09	2.39	4.55
2013	.78	.78	1.41	.81	3.78
2014	.61	1.07	1.52	*.80*	*4.00*
2015	*.75*	*.75*	*1.50*	*.75*	*3.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.32	.32	.32	.32	1.28
2012	.325	.325	.325	.325	1.30
2013	.3375	.3375	.3375	.3375	1.35
2014	.355	.355	.355	.355	1.42
2015	.4175				

BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison Company (SCE), which supplies electricity to 4.9 mill. customers in a 50,000 sq. mi. area in central, coastal, and southern California (excl. Los Angeles and San Diego). Discontinued Edison Mission Energy (independent power producer) in '12. Elec. revenue breakdown: residential, 40%; commercial, 42%; industrial, 5%; other, 13%. Generating sources: gas, 7%; nuclear, 6%; coal, 5%; hydro, 3%; purchased, 79%. Fuel costs: 35% of revs. '13 reported deprec. rate: 4.2%. Has 13,700 employees. Chairman, President & CEO: Theodore F. Craver, Jr. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Internet: www.edison.com.

Edison International's board of directors rewarded the company's stockholders with a large dividend increase. The board raised the annual dividend by $0.25 a share (17.6%), payable at the end of January. The company is targeting a payout ratio of 45%-55% of the profits of its utility subsidiary, Southern California Edison.

SCE's general rate case is pending. The utility is asking for rate hikes of $82 million in 2015, $295 million in 2016, and $313 million in 2017. On the other hand, the state's Office of Ratepayer Advocates and an intervenor group are proposing a *decrease* of $680 million this year, followed by increases of $98 million in 2016 and $116 million in 2017. The ruling will be retroactive to the start of 2015. No matter what happens with the rate order . . .

Earnings will probably decline in 2015. Edison International recorded some tax benefits in 2014, thereby making the profit comparison difficult. The tax rate will probably be higher this year. We expect earnings growth to resume in 2016. The utility is benefiting from its rising rate base, which is expected to climb 7%-9% annually through 2017.

The California commission approved a regulatory settlement concerning the San Onofre nuclear plant. SCE shut the two units in 2013 due to damage stemming from the replacement of the steam generators, and took a writedown. The utility will retain 5% of any insurance recoveries and 50% of any monies it gets from the manufacturer of the steam generators. SCE is involved in a dispute, which won't likely be resolved anytime soon, with the manufacturer.

Edison International was one of the top-performing electric utility stocks in 2014. The share price rose nearly 50%, as investors responded favorably to the resolution of the uncertainties surrounding San Onofre. The dividend hike helped, too. However, even though we have raised our sights for the 3- to 5-year period, with the recent price above the midpoint of our 2017-2019 Target Price Range, total return potential (like that of most utility issues) is low. The stock's dividend yield is also about a percentage point below the industry average.

Paul E. Debbas, CFA *January 30, 2015*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, $1.48; '03, (12¢); '04, $2.12; '09, (64¢); '10, 54¢; '11, ($3.33); '13, ($1.12); gains (loss) from discont. ops.: '12, ($5.11); '13, 11¢; '14, 44¢. '12 EPS don't add due to rounding. Next earnings report due late Feb. (B) Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '13: $22.22/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '13: 10.45%; earned on avg. com. eq., '13: 12.5%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	65

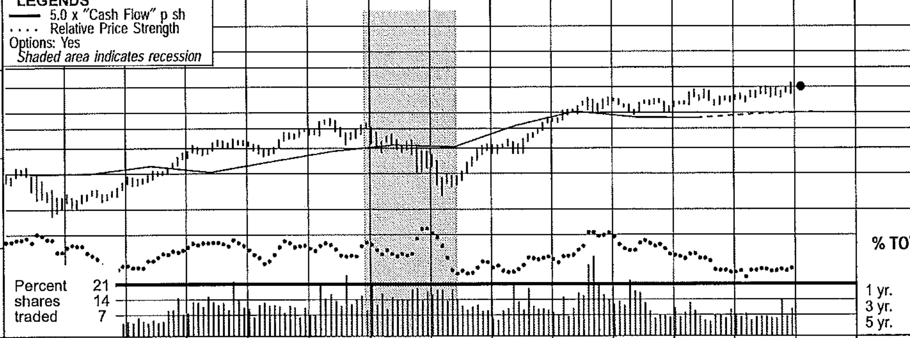
EL PASO ELECTRIC NYSE-EE

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
40.28	18.0	(Trailing: 18.4 / Median: 15.0)	0.98	2.9%	VALUE LINE

TIMELINESS 3 Lowered 12/5/14
SAFETY 2 Raised 5/11/07
TECHNICAL 3 Raised 11/28/14
BETA .70 (1.00 = Market)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
High:	13.6	19.1	22.4	25.0	28.2	25.5	21.1	28.7	35.7	35.3	39.1	42.2
Low:	10.1	13.1	17.8	18.2	20.8	15.2	11.6	18.7	26.7	29.2	31.8	33.4

LEGENDS
—— 5.0 x "Cash Flow" p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range

2017	2018	2019

2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+10%)	6%
Low	35	(-15%)	Nil

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	1	1	0	2	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	83	72	69
to Sell	75	90	76
Hld's(000)	39582	39656	40115

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.6	6.9
3 yr.	26.6	73.7
5 yr.	120.7	107.3

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
9.99	9.96	13.70	15.40	13.91	13.97	14.95	16.70	17.75	19.43	23.15	18.85	20.61	22.97	21.26	22.11	*22.85*	*23.35*	Revenues per sh	*26.75*
2.34	2.79	3.21	3.43	2.99	3.00	3.27	3.05	3.44	3.86	4.16	4.07	5.15	6.05	5.66	5.65	*5.90*	*6.05*	"Cash Flow" per sh	*7.25*
.70	.86	1.09	1.27	.57	.64	.69	.76	1.27	1.63	1.73	1.50	2.07	2.48	2.26	2.20	*2.30*	*2.05*	Earnings per sh A	*2.50*
--	--	--	--	--	--	--	--	--	--	--	--	--	.66	.97	1.05	1.11	*1.17*	Div'd Decl'd per sh B	*1.35*
1.08	1.28	1.70	1.85	1.75	2.03	1.94	2.28	2.73	4.63	5.36	5.95	5.27	5.90	6.70	7.18	*9.65*	*7.85*	Cap'l Spending per sh	*7.00*
6.92	7.36	8.05	9.01	9.20	10.51	11.23	11.56	12.60	14.76	15.47	16.45	19.04	19.03	20.57	23.44	*24.50*	*25.30*	Book Value per sh C	*28.25*
60.27	57.26	51.20	49.99	49.61	47.56	47.40	48.14	46.00	45.15	44.88	43.92	42.57	39.96	40.11	40.27	*40.50*	*40.70*	Common Shs Outst'g D	*41.30*
12.3	9.9	10.6	11.0	23.0	18.3	22.0	26.7	16.9	15.3	11.9	10.8	10.7	12.6	14.5	15.9	*16.2*		Avg Ann'l P/E Ratio	*15.5*
.64	.56	.69	.56	1.26	1.04	1.16	1.42	.91	.81	.72	.72	.68	.79	.92	.89	*.85*		Relative P/E Ratio	*.95*
--	--	--	--	--	--	--	--	--	--	--	--	--	2.1%	3.0%	3.0%	*3.0%*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $1089.2 mill. **Due in 5 Yrs** $187.7 mill.
LT Debt $984.7 mill. **LT Interest** $60.6 mill.
(LT interest earned: 2.7x)

Leases, Uncapitalized Annual rentals $1.1 mill.
Pension Assets-12/13 $257.8 mill.
Oblig. $317.8 mill.
Pfd Stock None

Common Stock 40,357,982 shs.
as of 10/31/14

MARKET CAP: $1.6 billion (Mid Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
708.6	803.9	816.5	877.4	1038.9	828.0	877.3	918.0	852.9	890.4	*925*	*950*	Revenues ($mill)	*1100*
33.4	36.6	61.4	74.8	77.6	66.9	90.3	103.5	90.8	88.6	*95.0*	*85.0*	Net Profit ($mill)	*105*
21.6%	33.7%	29.8%	31.6%	32.8%	33.1%	36.1%	34.2%	34.1%	33.0%	*30.5%*	*33.0%*	Income Tax Rate	*33.0%*
10.3%	15.8%	8.0%	15.9%	20.4%	24.3%	22.1%	17.6%	22.4%	24.1%	*30.0%*	*24.0%*	AFUDC % to Net Profit	*19.0%*
41.6%	52.3%	51.5%	49.6%	53.8%	52.7%	51.2%	51.8%	54.8%	51.4%	*53.5%*	*56.0%*	Long-Term Debt Ratio	*56.5%*
58.4%	47.7%	48.5%	50.4%	46.2%	47.3%	48.8%	48.2%	45.2%	48.6%	*46.5%*	*44.0%*	Common Equity Ratio	*43.5%*
911.8	1167.5	1195.8	1321.6	1503.9	1527.7	1660.1	1576.7	1824.5	1943.5	*2145*	*2330*	Total Capital ($mill)	*2700*
1283.0	1291.7	1332.2	1450.6	1595.6	1756.0	1865.8	1947.1	2102.3	2257.5	*2500*	*2660*	Net Plant ($mill)	*2975*
6.4%	4.9%	6.6%	7.1%	6.7%	6.0%	7.0%	8.3%	6.5%	6.1%	*6.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
6.3%	6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	*9.5%*	*8.0%*	Return on Shr. Equity	*9.0%*
6.3%	6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	*9.5%*	*8.0%*	Return on Com Equity E	*9.0%*
6.3%	6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	10.0%	6.3%	4.9%	*5.0%*	*3.5%*	Retained to Com Eq	*4.5%*
--	--	--	--	--	--	--	26%	43%	47%	*48%*	*56%*	All Div'ds to Net Prof	*53%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+3.1	+.7	+.4
Avg. Indust. Use (MWH)	21921	21659	21908
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1785	1765	1852
Peak Load, Summer (Mw)	1714	1688	1750
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.7	+1.5	+1.3
Fixed Charge Cov. (%)	346	302	280

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	4.5%	2.0%	*3.0%*
"Cash Flow"	6.5%	8.5%	*4.0%*
Earnings	11.0%	8.5%	*1.5%*
Dividends	--	--	*7.0%*
Book Value	8.0%	8.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	176.1	242.6	307.6	191.7	918.0
2012	168.6	228.3	267.2	188.8	852.9
2013	177.3	240.1	282.7	190.3	890.4
2014	185.5	251.8	283.6	*204.1*	*925*
2015	*195*	*255*	*295*	*205*	*950*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.16	.78	1.40	.13	2.48
2012	.08	.77	1.29	.12	2.26
2013	.19	.72	1.26	.03	2.20
2014	.11	.75	1.30	*.14*	*2.30*
2015	*.15*	*.65*	*1.15*	*.10*	*2.05*

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	--	.22	.22	.22	.66
2012	.22	.25	.25	.25	.97
2013	.25	.265	.265	.265	1.05
2014	.265	.28	.28	.28	1.11
2015					

BUSINESS: El Paso Electric Company (EPE) provides electric service to 398,000 customers in an area of approximately 10,000 square miles in the Rio Grande valley in western Texas (68% of revenues) and southern New Mexico (19% of revenues), including El Paso, Texas and Las Cruces, New Mexico. Wholesale is 13% of revenues. Electric revenue breakdown by customer class not available. Generating sources: nuclear, 46%; gas, 34%; coal, 6%; purchased, 14%. Fuel costs: 32% of revenues. '13 reported depreciation rate: 2.6%. Has about 1,000 employees. Chairman: Michael K. Parks. CEO: Thomas V. Shockley, III. President: Mary Kipp. Inc.: Texas. Address: Stanton Tower, 100 North Stanton, El Paso, Texas 79901. Telephone: 915-543-5711. Internet: www.epelectric.com.

The effects of regulatory lag for El Paso Electric in 2015 will be greater than we had expected. The company is building four 88-megawatt gas-fired peaking units. Two are expected to be in service by the end of the current quarter. A third unit will be on line in 2016, and a fourth in late 2016 or early 2017. (The total cost is estimated at $370 million.) The utility is planning to file rate cases in New Mexico in April and in Texas in August, with new tariffs taking effect in each state in March of 2016. This means that EPE won't get any rate relief this year, but will incur costs associated with the new units. In addition, the Allowance for Funds Used During Construction (a noncash credit to income) that the company will record in 2015 will be well below the 2014 level due to the completion of the first two units. All of this is will hurt earnings this year by an estimated $0.31-$0.37 a share. There will be some positive factors, too, such as customer growth that has been at 1.4% lately, but the negative will almost certainly outweigh the positive. All told, we have cut our 2015 earnings estimate by $0.15 a share, to $2.05.

We forecast higher profits in 2016. EPE should benefit from rate relief and continued growth in its service area (see below).

The company is financing its construction budget with debt. EPE issued $150 million of 30-year debt in December, and will probably issue the same amount (although with a shorter maturity) in late 2015.

The economy of the utility's service area is in good shape. For a few years, growth was driven by the expansion of the army base at Fort Bliss. Now, other factors are helping. Some companies have announced plans for new facilities and will hire workers. Other expansions are occurring at medical facilities and at the University of Texas at El Paso. All of this should help boost the demand for power.

The stock's dividend yield is a cut below the utility average. Although we project strong dividend growth over the 3- to 5-year period, total return prospects are unspectacular, given that the recent price is well within our 2017-2019 Target Price Range.

Paul E. Debbas, CFA *January 30, 2015*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '98, 6¢; '99, (38¢); '01, (4¢); '03, 81¢; '04, 4¢; '05, (2¢); '06, 13¢; '10, 24¢. '11 earnings don't add to full-year total due to rounding. Next earnings report due late Feb. (B) Initial dividend declared 4/11; payment dates in late March, June, Sept., and Dec. (C) Incl. deferred charges. In '13: $101.0 mill., $2.51/sh. (D) In millions. (E) Rate allowed on common equity in '12: none specified; earned on average common equity, '13: 10.0%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	80
Earnings Predictability	85

Staff/209
Muldoon/16

EMPIRE DISTRICT NYSE-EDE

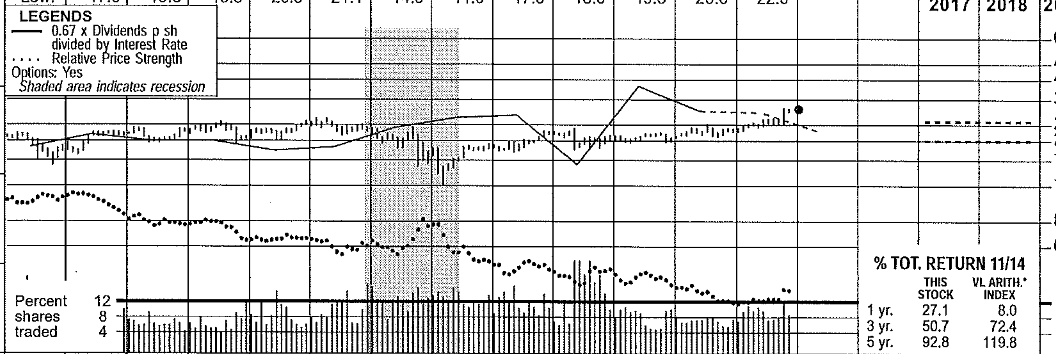
RECENT PRICE 28.73 | P/E RATIO 20.4 (Trailing: 17.5 Median: 16.0) | RELATIVE P/E RATIO 1.10 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 4 Lowered 12/5/14
SAFETY 2 Raised 3/23/12
TECHNICAL 4 Lowered 12/12/14
BETA .70 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
High:	22.5	23.5	25.0	25.1	26.1	23.5	19.4	22.5	23.3	22.0	24.3	29.2
Low:	17.0	19.5	19.3	20.3	21.1	14.9	11.9	17.6	18.0	19.5	20.6	22.0

Target Price Range
2017 | 2018 | 2019

LEGENDS
— 0.67 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(-15%)	1%
Low	20	(-30%)	-4%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	2	0	0	0	0	0	0
Options	0	5	0	0	0	0	0	4	0
to Sell	0	1	0	0	1	1	0	1	1

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	91	73	56
to Sell	42	63	69
Hld's(000)	21265	20869	20897

Percent shares traded 12 8 4

% TOT. RETURN 11/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.1	8.0
3 yr.	50.7	72.4
5 yr.	92.8	119.8

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
14.02	13.94	14.78	13.37	13.56	13.03	12.67	14.80	13.67	14.59	15.25	13.04	13.02	13.74	13.11	13.81	**15.15**	**15.45**	Revenues per sh	**16.75**
2.97	2.89	3.12	2.19	2.43	2.48	2.22	2.45	2.75	2.69	2.91	2.72	2.85	3.21	2.99	3.14	**3.45**	**3.60**	"Cash Flow" per sh	**4.25**
1.53	1.13	1.35	.59	1.19	1.29	.86	.92	1.41	1.09	1.17	1.18	1.17	1.31	1.32	1.48	**1.55**	**1.50**	Earnings per sh A	**1.75**
1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	.64	1.00	1.01	**1.03**	**1.05**	Div'd Decl'd per sh B ■ †	**1.15**
3.03	4.14	7.61	4.02	3.43	2.65	1.64	2.83	3.97	5.46	6.28	4.07	2.63	2.44	3.22	3.60	**5.15**	**4.05**	Cap'l Spending per sh	**3.50**
13.43	13.48	13.65	13.58	14.59	15.17	14.76	15.08	15.49	16.04	15.56	15.75	15.82	16.53	16.90	17.43	**17.95**	**18.35**	Book Value per sh C	**20.00**
17.11	17.37	17.60	19.76	22.57	24.98	25.70	26.08	30.25	33.61	33.98	38.11	41.58	41.98	42.48	43.04	**43.50**	**44.00**	Common Shs Outst'g D	**47.00**
14.0	21.7	17.7	33.9	16.2	15.8	24.8	24.5	15.9	21.7	17.3	14.3	16.8	15.8	15.8	15.0	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**13.0**
.73	1.24	1.15	1.74	.88	.90	1.31	1.30	.86	1.15	1.04	.95	1.07	.99	1.01	.85	*estimates*		Relative P/E Ratio	**.80**
6.0%	5.2%	5.4%	6.4%	6.6%	6.3%	6.0%	5.7%	5.7%	5.4%	6.3%	7.6%	6.5%	3.1%	4.8%	4.5%			Avg Ann'l Div'd Yield	**5.0%**
						325.5	386.2	413.5	490.2	518.2	497.2	541.3	576.9	557.1	594.3	**660**	**680**	Revenues ($mill)	**790**
						21.8	23.8	39.9	33.2	39.7	41.3	47.4	55.0	55.7	63.4	**65.0**	**65.0**	Net Profit ($mill)	**85.0**
						34.1%	33.4%	35.4%	30.3%	32.5%	32.5%	39.2%	38.4%	38.0%	37.1%	**36.5%**	**37.5%**	Income Tax Rate	**37.5%**
						1.0%	2.4%	10.7%	23.1%	31.5%	34.2%	21.5%	.9%	3.5%	9.4%	**15.0%**	**9.0%**	AFUDC % to Net Profit	**7.0%**
						51.3%	51.0%	49.7%	50.1%	53.6%	51.6%	51.3%	49.9%	49.1%	49.8%	**50.5%**	**50.5%**	Long-Term Debt Ratio	**50.0%**
						48.7%	49.0%	50.3%	49.9%	46.4%	48.4%	48.7%	50.1%	50.9%	50.2%	**49.5%**	**49.5%**	Common Equity Ratio	**50.0%**
						779.1	803.3	931.0	1081.1	1140.4	1240.3	1350.7	1386.2	1409.4	1493.6	**1585**	**1635**	Total Capital ($mill)	**1900**
						857.0	896.0	1031.0	1178.9	1342.8	1459.0	1519.1	1563.7	1657.6	1751.9	**1895**	**1980**	Net Plant ($mill)	**2050**
						4.7%	4.7%	5.9%	4.7%	5.2%	5.2%	5.1%	5.5%	5.4%	5.6%	**5.5%**	**5.5%**	Return on Total Cap'l	**6.0%**
						5.8%	6.0%	8.5%	6.2%	7.5%	6.9%	7.2%	7.9%	7.8%	8.5%	**8.5%**	**8.0%**	Return on Shr. Equity	**9.0%**
						5.8%	6.0%	8.5%	6.2%	7.5%	6.9%	7.2%	7.9%	7.8%	8.5%	**8.5%**	**8.0%**	Return on Com Equity E	**9.0%**
						NMF	NMF	.8%	NMF	NMF	NMF	NMF	4.1%	1.9%	2.7%	**3.0%**	**2.5%**	Retained to Com Eq	**3.5%**
						NMF	NMF	90%	117%	109%	109%	110%	49%	76%	68%	**66%**	**71%**	All Div'ds to Net Prof	**62%**

CAPITAL STRUCTURE as of 9/30/14
Total Debt $806.6 mill. **Due in 5 Yrs** $179.6 mill.
LT Debt $743.3 mill. **LT Interest** $39.4 mill.
Incl. $4.0 mill. capitalized leases.
(LT interest earned: 3.6x)
Leases, Uncapitalized Annual rentals $8.8 mill.
Pension Assets-12/13 $186.6 mill.
Oblig. $225.1 mill.
Pfd Stock None

Common Stock 43,439,071 shs.
as of 10/31/14

MARKET CAP: $1.2 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-2.3	-3.2	+1.3
Avg. Industrial Use (MWH)	2865	2913	2943
Avg. Industrial Rev/KWH (¢)	7.72	7.66	7.93
Capacity at Peak (Mw)	1392	1391	1377
Peak Load, Summer (Mw)	1198	1142	1080
Annual Load Factor (%)	52.0	52.2	56.2
% Change Customers (avg.)	-1.5	+.6	+.5
Fixed Charge Cov. (%)	307	314	331

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	--	-1.5%	3.5%
"Cash Flow"	3.0%	2.5%	5.5%
Earnings	3.0%	2.5%	4.0%
Dividends	-3.5%	-7.0%	4.5%
Book Value	1.5%	1.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	150.7	129.1	164.3	132.8	576.9
2012	137.2	131.6	159.2	129.1	557.1
2013	151.1	136.6	157.5	149.1	594.3
2014	179.7	149.8	171.5	**159**	**660**
2015	**170**	**160**	**180**	**170**	**680**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.29	.22	.60	.21	1.31
2012	.23	.25	.60	.23	1.32
2013	.30	.27	.56	.35	1.48
2014	.48	.26	.55	**.26**	**1.55**
2015	**.35**	**.25**	**.60**	**.30**	**1.50**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.32	.32	.32	.32	1.28
2011	.32	.32	--	--	.64
2012	.25	.25	.25	.25	1.00
2013	.25	.25	.25	.255	1.01
2014	.255	.255	.255	.26	

BUSINESS: The Empire District Electric Company supplies electricity to 169,000 customers in a 10,000 sq. mi. area in southwestern Missouri (90% of '13 retail elec. revs.), Kansas (5%), Oklahoma (3%), & Arkansas (2%). Acquired Missouri Gas (44,000 customers) 6/06. Supplies water service (4,000 customers) and has a small fiber-optics operation. Elec. rev. breakdown: residential, 43%; commercial, 30%; industrial, 15%; other, 12%. Generating sources: coal, 47%; gas, 24%; hydro, 1%; purch., 28%. Fuel costs: 34% of revs. '13 reported depr. rate: 3.1%. Has about 750 employees. Chairman: D. Randy Laney. President & CEO: Bradley P. Beecher. Inc.: KS. Address: 602 S. Joplin Ave., P.O. Box 127, Joplin, MO 64802-0127. Tel.: 417-625-5100. Internet: www.empiredistrict.com.

Empire District Electric Company has a rate case pending in Missouri. The utility is seeking an electric rate increase of $24.3 million (5.5%), based on a return of 10.15% on a common-equity ratio of 51.45%. The main reason for the filing is an environmental retrofit to the 189-megawatt Asbury coal-fired plant. This project is on track for completion in early 2015. The cost is trending towards the lower end of the estimated range of $112 million-$130 million. Empire District also wants to recoup higher expenses, such as property taxes, and start recovering transmission costs through its fuel adjustment clause. An order should come in July.

The utility has filed or plans to file rate cases in its other states. This will enable it to recover the portion of the Asbury project that is allocated to each state. Empire District has asked the Kansas commission for a rider on customers' bills.

Empire District received a rate hike in Arkansas. Rates were raised by $1.4 million, based on a 9.9% ROE. New tariffs took effect on September 26th.

Next year will be a challenging one for the company. In 2014, earnings will probably advance, thanks to a strong first-quarter showing that was driven partly by favorable weather conditions. Our estimate is at the midpoint of Empire District's targeted range of $1.50-$1.60 a share. However, because the utility will incur some costs associated with the Asbury project before recovering them in rates, there will be some regulatory lag in 2015. Accordingly, we forecast a slight profit decrease.

The board of directors raised the dividend in the fourth quarter. The annual increase was modest, at $0.02 a share (2%). The dividend is still well below its level before the board suspended it in 2011, following a tornado that devastated Joplin, Missouri. (The service area has made a solid recovery since then.)

The recent price is *above* our 2017-2019 Target Price Range. We suspect that this is due to takeover speculation. Indeed, Empire District agreed to a buyout in 1999, but the deal fell through. The stock is untimely and has a lofty valuation, and we do not recommend that investors buy it for takeover possibilities.

Paul E. Debbas, CFA *December 19, 2014*

(A) Diluted earnings. Excl. loss from discontinued operations: '06, 2¢. '11 & '12 EPS don't add due to rounding. Next earnings report due early Feb. (B) Div'ds historically paid in mid-Mar., June, Sept. and Dec. Div'ds suspended 3Q '11, reinstated 1Q '12. ■ Div'd reinvestment plan avail. (3% discount). † Shareholder investment plan avail. (C) Incl. intang. In '13: $5.06/sh. (D) In mill. (E) Rate base: Deprec. orig. cost. Rate allowed on com. eq. in MO in '13: none specified; earned on avg. com. eq., '13: 8.7%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	30
Earnings Predictability	85

Staff/209
Muldoon/17

ENTERGY CORP. NYSE-ETR

RECENT PRICE 83.98 | P/E RATIO 17.4 (Trailing: 14.3 Median: 14.0) | RELATIVE P/E RATIO 0.94 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 4 Lowered 12/5/14
SAFETY 3 Lowered 3/22/13
TECHNICAL 4 Lowered 11/7/14
BETA .70 (1.00 = Market)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
High:	57.2	68.7	79.2	94.0	125.0	127.5	86.6	84.3	74.5	74.5	72.6	85.0
Low:	42.3	50.6	64.5	66.8	89.6	61.9	59.9	68.7	57.6	61.6	60.2	60.4

2017-19 PROJECTIONS

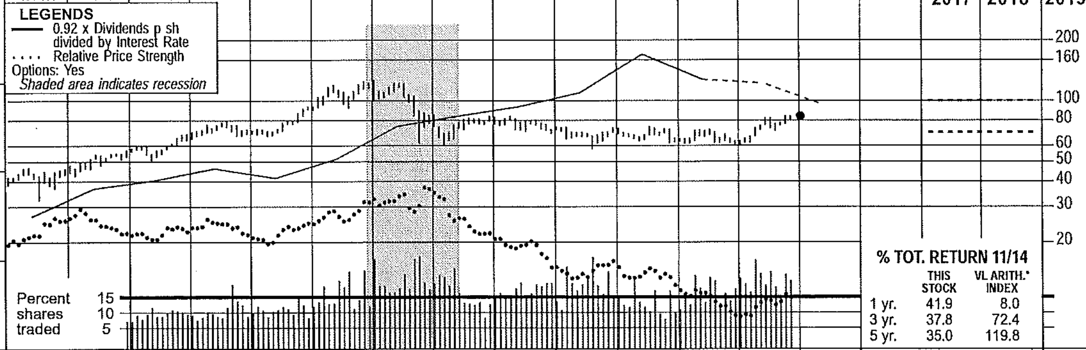
	Price	Gain	Ann'l Total Return
High	100	(+20%)	8%
Low	70	(-15%)	Nil

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	6	0	3	4	2	0	2	1
to Sell	0	6	0	3	4	2	0	2	1

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	245	237	241
to Sell	194	209	206
Hld's(000)	151069	156315	158821



1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
46.57	35.51	45.61	43.59	37.34	40.17	46.69	46.61	53.94	59.47	69.15	56.82	64.27	63.67	57.94	63.86	**69.80**	**70.35**	Revenues per sh	**81.50**
6.11	5.06	6.49	6.41	7.62	7.43	8.33	8.18	10.69	11.73	12.89	13.29	16.54	17.53	15.98	16.25	**17.95**	**17.85**	"Cash Flow" per sh	**20.75**
2.22	2.25	2.97	3.08	3.68	3.69	3.93	4.40	5.36	5.60	6.20	6.30	6.66	7.55	6.02	4.96	**5.90**	**5.45**	Earnings per sh A	**6.75**
1.50	1.20	1.22	1.28	1.34	1.60	1.89	2.16	2.16	2.58	3.00	3.00	3.24	3.32	3.32	3.32	**3.32**	**3.32**	Div'd Decl'd per sh B ■ †	**3.80**
4.63	4.84	6.80	6.25	6.88	6.85	6.51	6.72	9.44	10.29	13.92	12.99	13.33	15.21	18.18	15.73	**16.70**	**15.55**	Cap'l Spending per sh	**15.50**
28.79	28.81	31.89	33.78	35.24	38.02	38.26	35.71	40.45	40.71	42.07	45.54	47.53	50.81	51.73	54.00	**55.85**	**58.00**	Book Value per sh C	**65.75**
246.83	247.08	219.60	220.73	222.42	228.90	216.83	216.83	202.67	193.12	189.36	189.12	178.75	176.36	177.81	178.37	**180.50**	**180.50**	Common Shs Outst'g D	**180.50**
12.9	13.2	10.1	12.5	11.5	13.8	15.1	16.3	14.3	19.3	16.6	12.0	11.6	9.1	11.2	13.2	*Bold figures are*		Avg Ann'l P/E Ratio	**12.5**
.67	.75	.66	.64	.63	.79	.80	.87	.77	1.02	1.00	.80	.74	.57	.71	.74	*Value Line*		Relative P/E Ratio	**.80**
5.2%	4.1%	4.1%	3.3%	3.2%	3.1%	3.2%	3.0%	2.8%	2.4%	2.9%	4.0%	4.2%	4.9%	4.9%	5.1%	*estimates*		Avg Ann'l Div'd Yield	**4.5%**

CAPITAL STRUCTURE as of 9/30/14
Total Debt $13643 mill. **Due in 5 Yrs** $4832.9 mill.
LT Debt $11635 mill. **LT Interest** $556.5 mill.
Incl. $814.2 mill. of securitization bonds.
(LT interest earned: 3.2x)
Leases, Uncapitalized Annual rentals $106.2 mill.
Pension Assets-12/13 $4429.2 mill.
Oblig. $5771.0 mill.
Pfd Stock $304.8 mill. **Pfd Div'd** $19.5 mill.
6,115,105 sh. 4.32%-8.25%, $100 par; 1,000,000 sh. 8.95%; 250,000 sh. 8.75%, all without sinking fund.
Common Stock 180,481,135 shs. **as of 10/31/14**
MARKET CAP: $15 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
10124	10106	10932	11484	13094	10746	11488	11229	10302	11391	**12600**	**12700**	Revenues ($mill)	**14700**
933.1	943.1	1160.9	1160.0	1240.5	1251.1	1270.3	1367.4	1091.9	904.5	**1085**	**1005**	Net Profit ($mill)	**1250**
28.2%	37.2%	27.6%	30.7%	32.7%	33.6%	32.7%	17.3%	13.0%	26.7%	**37.0%**	**33.0%**	Income Tax Rate	**35.0%**
7.0%	8.0%	5.5%	5.8%	5.6%	7.4%	7.4%	8.9%	11.9%	10.1%	**9.0%**	**10.0%**	AFUDC % to Net Profit	**7.0%**
44.7%	51.9%	51.2%	54.3%	58.2%	55.3%	56.3%	52.2%	55.8%	55.1%	**55.5%**	**58.0%**	Long-Term Debt Ratio	**54.5%**
52.9%	45.5%	46.7%	43.9%	40.2%	43.1%	42.1%	46.4%	42.9%	43.6%	**43.0%**	**41.0%**	Common Equity Ratio	**44.0%**
15696	17013	17539	17902	19795	19985	20166	19324	21432	22109	**23450**	**25550**	Total Capital ($mill)	**26900**
18696	19197	19438	20974	22429	23389	23848	25609	27299	27882	**28775**	**29400**	Net Plant ($mill)	**30700**
7.4%	6.8%	8.0%	7.9%	7.5%	7.6%	7.7%	8.5%	6.4%	5.4%	**6.0%**	**5.0%**	Return on Total Cap'l	**6.0%**
10.8%	11.5%	13.6%	14.2%	15.0%	14.0%	14.4%	14.8%	11.5%	9.1%	**10.5%**	**9.5%**	Return on Shr. Equity	**10.5%**
11.0%	11.9%	13.8%	14.4%	15.3%	14.3%	14.7%	15.0%	11.6%	9.2%	**10.5%**	**9.5%**	Return on Com Equity E	**10.5%**
5.8%	6.0%	8.3%	8.0%	8.1%	7.6%	7.6%	8.4%	5.2%	3.0%	**4.5%**	**3.5%**	Retained to Com Eq	**4.5%**
48%	51%	41%	46%	48%	48%	49%	45%	56%	68%	**57%**	**62%**	All Div'ds to Net Prof	**57%**

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+1.1	-1.5	+.7
Avg. Indust. Use (MWH)	991	975	910
Avg. Indust. Revs. per KWH(¢)	5.65	4.94	5.77
Capacity at Peak (Mw)	23979	23407	23802
Peak Load, Summer (Mw)	22387	21866	21581
Annual Load Factor (%)	60.0	60.0	62.0
% Change Customers (yr-end)	+.5	+.8	+.8
Fixed Charge Cov. (%)	339	254	245

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	4.5%	.5%	*4.5%*
"Cash Flow"	9.0%	7.0%	*4.0%*
Earnings	6.0%	1.5%	*1.5%*
Dividends	9.0%	5.0%	*2.5%*
Book Value	4.0%	5.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	2541	2803	3396	2489	11229
2012	2384	2519	2964	2436	10302
2013	2609	2738	3352	2692	11391
2014	3209	2997	3458	*2936*	*12600*
2015	*2950*	*3050*	*3650*	*3050*	*12700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	1.38	1.76	3.53	.88	7.55
2012	.40	2.06	1.89	1.67	6.02
2013	.90	.92	2.31	.83	4.96
2014	2.28	1.08	1.68	*.86*	*5.90*
2015	*1.15*	*1.15*	*2.00*	*1.15*	*5.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.75	.83	.83	.83	3.24
2011	.83	.83	.83	.83	3.32
2012	.83	.83	.83	.83	3.32
2013	.83	.83	.83	.83	3.32
2014	.83	.83	.83	.83	

BUSINESS: Entergy Corporation supplies electricity to 2.8 million customers through subsidiaries in Arkansas, Louisiana, Mississippi, Texas, and New Orleans (regulated separately from Louisiana). Distributes gas to 196,000 customers in Louisiana. Has a nonutility nuclear subsidiary that owns six units. Electric revenue breakdown: residential, 38%; commercial, 26%; industrial, 28%; other, 8%. Generating sources: nuclear, 33%; gas, 26%; coal, 12%; purchased, 29%. Fuel costs: 35% of revenues. '13 reported depreciation rate: 2.8%. Has 13,800 employees. Chairman & CEO: Leo Denault. Incorporated: Delaware. Address: 639 Loyola Avenue, P.O. Box 61000, New Orleans, Louisiana 70161. Telephone: 504-576-4000. Internet: www.entergy.com.

Entergy has announced a significant asset acquisition. Three of its utility subsidiaries (in Arkansas, Louisiana, and Texas) have agreed to pay $948 million for a 1,980-megawatt gas-fired generating station. The purchase would help the utilities meet the rising demand for power in their service areas. The deal requires the approval of each state's regulatory commission and the Federal Energy Regulatory Commission. It is expected to be completed in late 2015.

Entergy is about to receive an order on its rate case in Mississippi. The utility filed for a $49 million increase, based on a 10.59% return on equity, but reached a settlement calling for a $16 million hike, based on a 10.07% ROE. New tariffs will take effect in 2015.

Earnings will probably wind up significantly higher in 2014. First-quarter profits were much higher than normal due to favorable weather conditions. The weather led to high and volatile power prices in the Northeast, which benefited Entergy's nonregulated operation and added $0.90 a share to the bottom line.

We forecast lower profits in 2015. We assume normal weather patterns, which would almost certainly result in much lower earnings in the first quarter. Even so, Entergy should turn in a decent performance. The company's utilities are benefiting from growth in demand in their service territories. Entergy expects load growth of 3.0%-3.5% in 2015.

The future of the Indian Point nuclear station is still a cause for concern. Entergy wants to extend the two units' operating licenses by 20 years. However, officials in New York State want to shut down the plant, reduce its output, or force the company to install cooling towers, which would be costly.

The price of untimely Entergy stock has risen 33% in 2014. That's even better than most utility equities have fared in what has been an outstanding year for electric utilities. Despite the worries about Indian Point, there are signs that the long-term prospects of the nonregulated business are getting better. The dividend yield is about half of a percentage point above the industry average, but 3- to 5-year total return potential is unexciting.

Paul E. Debbas, CFA *December 19, 2014*

(A) Diluted EPS. Excl. nonrecurring gains (losses): '98, 78¢; '01, 15¢; '02, ($1.04); '03, 33¢ net; '05, (21¢); '12, ($1.26); '13, ($1.14); '14, (48¢). Next earnings report due early Feb. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. deferred charges. In '13: $29.67/sh. (D) In millions. (E) Rate base: Net original cost. Allowed return on equity (blended): 10.4%; earned on avg. com. eq., '13: 9.3%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	25
Earnings Predictability	85

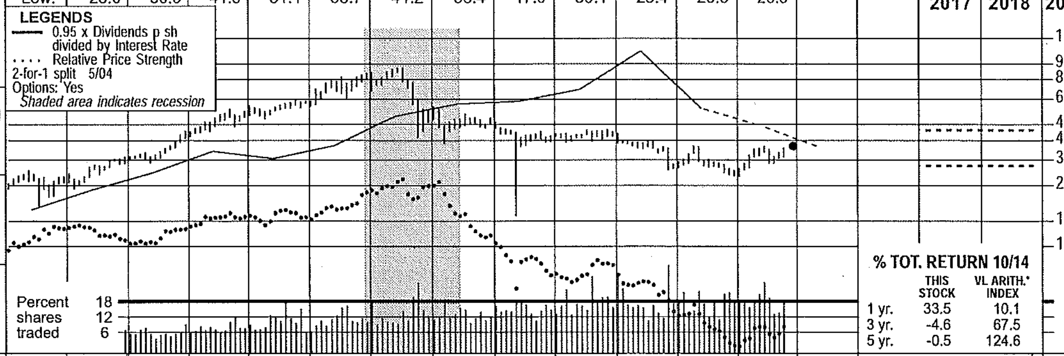
EXELON CORP. NYSE-EXC

RECENT PRICE 37.55 | P/E RATIO 13.9 (Trailing: 17.0 Median: 15.0) | RELATIVE P/E RATIO 0.76 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 3 Lowered 9/5/14
SAFETY 3 Lowered 11/23/12
TECHNICAL 4 Lowered 10/17/14
BETA .70 (1.00 = Market)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
High:	33.3	44.9	57.5	63.6	86.8	92.1	59.0	49.9	45.4	43.7	37.8	37.9
Low:	23.0	30.9	41.8	51.1	58.7	41.2	38.4	17.0	39.1	28.4	26.6	26.5

Target Price Range 2017 | 2018 | 2019



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+20%)	8%
Low	30	(-20%)	-1%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	12	2	2	0	0	0	0	0
to Sell	0	0	1	0	0	0	0	0	0

Institutional Decisions

	4Q2013	1Q2014	2Q2014
to Buy	284	322	319
to Sell	353	315	327
Hld's(000)	614658	630607	686965

% TOT. RETURN 10/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	33.5	10.1
3 yr.	-4.6	67.5
5 yr.	-0.5	124.6

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
--	19.40	11.75	23.58	23.13	23.89	21.85	23.06	23.37	28.62	28.66	26.24	28.16	28.54	27.47	29.04	*30.70*	*30.70*	Revenues per sh	*32.75*
--	3.55	1.84	5.06	5.03	5.02	5.68	6.19	6.71	7.43	7.64	8.24	8.32	7.24	6.60	6.73	*6.50*	*7.05*	"Cash Flow" per sh	*7.75*
--	1.86	1.39	2.20	2.40	2.44	2.75	3.21	3.50	4.03	4.10	4.29	3.87	3.75	1.92	2.31	*2.10*	*2.65*	Earnings per sh A	*3.25*
--	--	--	.91	.88	.96	1.26	1.60	1.64	1.82	2.05	2.10	2.10	2.10	2.10	1.46	*1.24*	*1.24*	Div'd Decl'd per sh B ■	*1.50*
--	--	1.18	3.18	3.33	2.95	2.89	3.25	3.61	4.05	4.74	4.96	5.02	6.10	6.77	6.30	*6.75*	*7.75*	Cap'l Spending per sh	*6.00*
--	--	11.31	12.82	11.97	12.84	14.19	13.70	14.89	15.34	16.79	19.15	20.48	21.70	25.07	26.53	*27.60*	*28.95*	Book Value per sh C	*33.75*
--	630.20	638.01	642.01	646.63	662.00	664.20	666.00	670.00	661.00	658.00	660.00	662.00	663.00	855.00	857.00	*860.00*	*863.00*	Common Shs Outst'g D	*900.00*
--	--	22.4	13.2	10.5	11.8	13.0	15.4	16.5	18.2	18.0	11.5	11.0	11.3	19.1	13.4	*Bold figures are*		Avg Ann'l P/E Ratio	*11.0*
--	--	1.46	.68	.57	.67	.69	.82	.89	.97	1.08	.77	.70	.71	1.22	.75	*Value Line*		Relative P/E Ratio	*.70*
--	--	--	3.1%	3.5%	3.4%	3.5%	3.2%	2.8%	2.5%	2.8%	4.3%	4.9%	5.0%	5.7%	4.7%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 6/30/14
Total Debt $21449 mill. **Due in 5 Yrs** $7832 mill.
LT Debt $18781 mill. **LT Interest** $901 mill.
Includes $648 mill. nonrecourse transition bonds.
(LT interest earned: 4.3x)
Leases, Uncapitalized Annual rentals $103 mill.
Pension Assets-12/13 $13571 mill.
Oblig. $15459 mill.
Pfd Stock $193 mill. **Pfd Div'd** $13 mill.
Includes $193 mill. in preferred securities of subsidiaries.
Common Stock 859,197,443 shs.

MARKET CAP: $32 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
14515	15357	15655	18916	18859	17318	18644	18924	23489	24888	*26400*	*26500*	Revenues ($mill)	*29500*
1844.0	2162.0	2370.0	2730.0	2721.0	2844.0	2567.0	2499.0	1579.0	1999.0	*1955*	*2285*	Net Profit ($mill)	*2865*
27.5%	30.4%	33.7%	34.6%	32.6%	38.8%	39.2%	36.8%	32.4%	36.5%	*25.0%*	*32.0%*	Income Tax Rate	*32.0%*
.9%	1.0%	1.6%	1.8%	1.3%	2.3%	2.1%	3.0%	5.8%	4.5%	*5.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
56.1%	56.1%	54.2%	53.9%	53.1%	47.2%	46.8%	45.7%	45.8%	44.4%	*44.5%*	*44.0%*	Long-Term Debt Ratio	*41.5%*
43.5%	43.5%	45.4%	45.7%	46.6%	52.4%	52.9%	54.0%	53.5%	55.2%	*55.5%*	*55.5%*	Common Equity Ratio	*58.0%*
21658	20972	21971	22189	23726	24112	25651	26661	40057	41196	*42925*	*44825*	Total Capital ($mill)	*52300*
21482	21981	22775	24153	25813	27341	29941	32570	45186	47330	*49875*	*53225*	Net Plant ($mill)	*59900*
10.4%	12.1%	12.5%	14.1%	13.1%	13.3%	11.4%	10.6%	5.1%	5.9%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.5%*
19.4%	23.5%	23.6%	26.7%	24.4%	22.3%	18.8%	17.3%	7.3%	8.7%	*7.5%*	*9.0%*	Return on Shr. Equity	*9.5%*
19.5%	23.6%	23.7%	26.9%	24.6%	22.5%	18.9%	17.3%	7.3%	8.7%	*7.5%*	*9.0%*	Return on Com Equity E	*9.5%*
10.7%	11.9%	13.0%	15.3%	12.5%	11.5%	8.7%	7.7%	NMF	3.2%	*3.0%*	*5.0%*	Retained to Com Eq	*5.0%*
45%	50%	45%	43%	49%	49%	54%	56%	109%	63%	*56%*	*47%*	All Div'ds to Net Prof	*47%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-2.0	+18.9	-.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	32736	32150	NA
Nuclear Capacity Factor (%)	93.3	92.7	94.1
% Change Customers (yr-end)	+.3	+23.6	+.6
Fixed Charge Cov. (%)	569	293	338

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	2.0%	1.0%	2.5%
"Cash Flow"	3.0%	-1.0%	2.0%
Earnings	1.5%	-7.5%	3.5%
Dividends	7.5%	.5%	-3.5%
Book Value	7.0%	9.5%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	5052	4587	5295	3990	18924
2012	4686	5954	6565	6284	23489
2013	6082	6141	6502	6163	24888
2014	7237	6024	6912	*6227*	*26400*
2015	*7000*	*6200*	*7000*	*6300*	*26500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	1.01	.93	.90	.91	3.75
2012	.54	.33	.57	.49	1.92
2013	.30	.57	.86	.59	2.31
2014	.10	.60	.92	*.48*	*2.10*
2015	*.70*	*.60*	*.75*	*.60*	*2.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.525	.525	.525	.525	2.10
2011	.525	.525	.525	.525	2.10
2012	.525	.525	.525	.525	2.10
2013	.525	.31	.31	.31	1.46
2014	.31	.31	.31		

BUSINESS: Exelon Corporation is a holding company for Commonwealth Edison (3.9 mill. elec. customers in IL), PECO Energy, (1.6 mill. elec., 501,000 gas customers in PA), & Baltimore Gas and Electric (1.2 mill. elec., 656,000 gas customers in MD). Has nonregulated generating & energy-marketing ops. Acq'd Constellation Energy 3/12. Elec. rev. breakdown: res'l, 59%; small comm'l & ind'l, 24%; large comm'l & ind'l, 7%; other, 10%. Generating sources: nuclear, 57%; other, 15%; purch., 28%. Fuel costs: 43% of revs. '13 depr. rates: 2.9%-3.4% elec., 2.1% gas. Has 25,800 empls. Chairman: Mayo A. Shattuck III. Pres. & CEO: Christopher M. Crane. Inc.: PA. Address: 10 S. Dearborn St., P.O. Box 805379, Chicago, IL 60680-5379. Tel.: 312-394-7398. Internet: www.exeloncorp.com.

Exelon's proposed acquisition of Pepco Holdings has taken a small step forward. The agreement calls for Exelon to pay $6.8 billion in cash for Pepco, which owns utilities in Washington, DC; the Delmarva Peninsula; and the southern third of New Jersey. Pepco shareholders voted in favor of the offer. The transaction still requires the approval of the regulators in DC, Delaware, Maryland, and New Jersey, along with the Federal Energy Regulatory Commission. The companies expect the takeover to be completed in the second or third quarter of 2015. Exelon anticipates the purchase to boost share net by $0.10-$0.15 in 2016 and $0.15-$0.20 in 2017, but our estimates and projections will not include Pepco until the deal has closed.

Exelon has already taken some steps to finance the acquisition. The company executed a forward sale agreement for 57.5 million common shares. It has sold and is selling some noncore generating assets to raise $1.4 billion. One sale produced a $0.23-a-share nonrecurring gain in the third quarter, but another will result in a pretax loss of $350 million-$450 million this quarter. This hardly means that Exelon is exiting the generating business—the company plans to build two gas-fired plants in Texas for $1.4 billion.

Another purchase has been completed. Exelon paid $50 million, plus net working capital, for the retail energy services operation owned by Integrys Energy. The deal almost doubled the size of its business, to 2.5 million customers.

Exelon Generation is seeing positive signs. Forward power prices for 2015 are higher than at the start of 2014. Also, proposals pending in the PJM power pool would raise capacity prices paid to owners of generating assets.

Baltimore Gas and Electric has reached a settlement of its rate case. The agreement, subject to approval of the Maryland commission, calls for a total (electric and gas) rate hike of $60 million and a $20 million reduction in depreciation and amortization.

Exelon's improved prospects are reflected in the quotation. The share price is up 37% since the start of 2014. The yield and 3- to 5-year total return potential are about average for a utility.

Paul E. Debbas, CFA *November 21, 2014*

(A) Dil. egs. Excl. nonrec. gain (losses): '02, (18¢); '03, ($1.06); '05, ($1.85); '06, ($1.15); '09, (20¢); '12, (50¢); '13, (31¢); '14, 23¢. '12 & '13 EPS don't add due to change in shares or rounding. Next earnings report due early Feb. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. def'd charges. In '13: $10.79/sh. (D) In mill., adj. for split. (E) Rate allowed on com. eq. in IL in '11: 10.5%; in MD in '13: 9.75% elec., 9.6% gas; earned on avg. com. eq., '13: 9.1%. Regulat. Climate: PA, Avg.; IL, MD, Below Avg.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	15
Earnings Predictability	70

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Muldoon/19

FIRSTENERGY NYSE-FE

RECENT PRICE 37.29 | P/E RATIO 14.1 (Trailing: 14.9 / Median: 15.0) | RELATIVE P/E RATIO 0.77 | DIV'D YLD 3.9% | VALUE LINE

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
High:	38.9	43.4	53.4	61.7	75.0	84.0	53.6	47.8	46.5	51.1	46.8	37.7
Low:	25.8	35.2	37.7	47.8	57.8	41.2	35.3	33.6	36.1	40.4	31.3	30.0

TIMELINESS 3 Lowered 9/5/14
SAFETY 3 Lowered 2/22/13
TECHNICAL 3 Lowered 10/17/14
BETA .70 (1.00 = Market)

2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+20%)	9%
Low	30	(-20%)	Nil

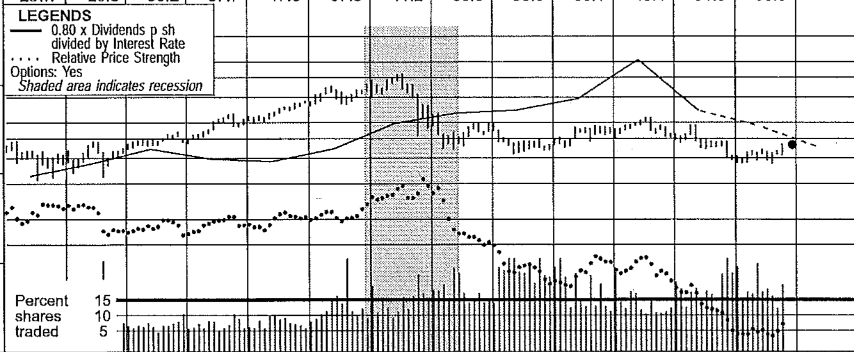
Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	0	1	0	0	0	0	0
to Sell	0	1	0	1	0	2	0	0	1

Institutional Decisions

	4Q2013	1Q2014	2Q2014
to Buy	242	211	208
to Sell	226	238	210
Hld's(000)	295953	303716	300665

LEGENDS
— 0.80 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range
2017 | 2018 | 2019
128
96
80
64
48
40
32
24
16
12

% TOT. RETURN 10/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.5	10.1
3 yr.	-3.6	67.5
5 yr.	10.4	124.6

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
24.72	27.19	31.31	26.88	40.83	37.31	37.76	36.35	36.03	42.00	44.70	41.70	43.76	38.87	36.57	35.60	*36.10*	*36.60*	Revenues per sh	*39.00*
5.33	6.89	7.28	5.48	6.45	4.79	7.60	7.55	7.22	8.34	9.04	8.80	8.50	5.75	6.05	6.30	*5.55*	*6.25*	"Cash Flow" per sh	*6.75*
1.95	2.50	2.69	2.84	2.54	1.47	2.77	2.84	3.82	4.22	4.38	3.32	3.25	1.88	2.13	2.97	*2.10*	*2.75*	Earnings per sh A	*3.00*
1.50	1.50	1.50	1.50	1.50	1.50	1.91	1.71	1.85	2.05	2.20	2.20	2.20	2.20	2.20	1.65	*1.44*	*1.44*	Div'd Decl'd per sh B ■	*1.60*
2.75	2.69	2.74	2.86	3.35	2.60	2.57	3.66	4.12	5.36	9.47	7.23	6.44	5.45	7.09	6.90	*8.60*	*6.95*	Cap'l Spending per sh	*7.25*
18.77	19.63	20.72	24.86	23.92	25.13	26.04	27.86	28.30	29.45	27.17	28.08	28.03	31.75	31.29	30.32	*31.05*	*32.35*	Book Value per sh C	*36.25*
237.07	232.45	224.53	297.64	297.64	329.84	329.84	329.84	319.21	304.84	304.84	304.84	304.84	418.22	418.22	418.63	*421.00*	*423.50*	Common Shs Outst'g D	*431.00*
15.4	11.3	9.2	10.9	13.0	22.5	14.1	16.1	14.2	15.6	15.6	13.0	11.7	22.4	21.1	13.1	*Bold figures are*		Avg Ann'l P/E Ratio	*12.5*
.80	.64	.60	.56	.71	1.28	.74	.86	.77	.83	.94	.87	.74	1.41	1.34	.74	*Value Line*		Relative P/E Ratio	*.80*
5.0%	5.3%	6.1%	4.8%	4.6%	4.5%	4.9%	3.7%	3.4%	3.1%	3.2%	5.1%	5.8%	5.2%	4.9%	4.3%	*estimates*		Avg Ann'l Div'd Yield	*4.3%*

CAPITAL STRUCTURE as of 6/30/14
Total Debt $21754 mill. **Due in 5 Yrs** $9577 mill.
LT Debt $18415 mill. **LT Interest** $965 mill.
Incl. $154 mill. capitalized leases.
(LT interest earned: 2.6x)

Leases, Uncapitalized Annual rentals $202 mill.
Pension Assets-12/13 $6171 mill.
Oblig. $8263 mill.
Pfd Stock None

Common Stock 420,344,546 shs.
as of 7/31/14
MARKET CAP: $16 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
12453	11989	11501	12802	13627	12712	13339	16258	15294	14903	*15200*	*15500*	Revenues ($mill)	*16800*
932.6	951.0	1265.0	1309.0	1342.0	1015.0	991.0	752.0	891.0	1245.0	*895*	*1165*	Net Profit ($mill)	*1300*
42.2%	42.1%	38.6%	40.3%	36.7%	19.6%	38.6%	41.3%	41.1%	36.1%	*30.5%*	*37.0%*	Income Tax Rate	*35.5%*
2.7%	2.0%	2.1%	2.4%	3.9%	12.8%	16.6%	9.3%	8.1%	6.0%	*12.0%*	*6.0%*	AFUDC % to Net Profit	*6.0%*
52.8%	46.5%	48.6%	49.7%	52.4%	58.2%	59.5%	54.2%	53.7%	55.5%	*56.0%*	*55.5%*	Long-Term Debt Ratio	*55.0%*
45.4%	52.4%	51.4%	50.3%	47.7%	41.8%	40.5%	45.8%	46.3%	44.5%	*44.0%*	*44.5%*	Common Equity Ratio	*45.0%*
18938	17527	17570	17846	17383	20467	21124	28996	28263	28523	*29600*	*30850*	Total Capital ($mill)	*34800*
13478	13998	14667	15383	17723	19164	19788	30337	32903	33252	*35500*	*37025*	Net Plant ($mill)	*41400*
6.5%	7.1%	9.0%	9.0%	9.7%	6.9%	6.3%	4.0%	4.9%	6.0%	*4.5%*	*5.5%*	Return on Total Cap'l	*5.0%*
10.4%	10.1%	14.0%	14.6%	16.2%	11.9%	11.6%	5.7%	6.8%	9.8%	*7.0%*	*8.5%*	Return on Shr. Equity	*8.5%*
10.6%	10.2%	13.9%	14.6%	16.2%	11.9%	11.6%	5.7%	6.8%	9.8%	*7.0%*	*8.5%*	Return on Com Equity E	*8.5%*
4.9%	4.2%	7.4%	7.7%	8.1%	4.0%	3.8%	NMF	NMF	2.6%	*2.0%*	*4.0%*	Retained to Com Eq	*4.0%*
55%	59%	47%	47%	50%	66%	68%	117%	103%	74%	*68%*	*52%*	All Div'ds to Net Prof	*53%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+.1	+3.5	+.9
Avg. Indust. Use (MWH)	NMF	NMF	NMF
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	206	236	294

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	.5%	-2.0%	*1.0%*
"Cash Flow"	1.0%	-6.0%	*2.0%*
Earnings	--	-11.0%	*4.5%*
Dividends	3.0%	--	*-4.0%*
Book Value	2.5%	2.0%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	3576	4060	4719	3903	16258
2012	3986	3757	4051	3500	15294
2013	3724	3512	4020	3647	14903
2014	4189	3496	3888	*3627*	*15200*
2015	*4050*	*3750*	*4000*	*3700*	*15500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.15	.48	1.27	d.09	1.88
2012	.78	.52	1.05	d.23	2.13
2013	.51	.47	.88	1.11	2.97
2014	.34	.27	.79	*.70*	*2.10*
2015	*.65*	*.50*	*.85*	*.75*	*2.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.55	.55	.55	.55	2.20
2011	.55	.55	.55	.55	2.20
2012	.55	.55	.55	.55	2.20
2013	.55	.55	.55	.55	2.20
2014	.36	.36	.36		

BUSINESS: FirstEnergy Corp. is a holding company for Ohio Edison, Pennsylvania Power, Cleveland Electric, Toledo Edison, Metropolitan Edison, Penelec, Jersey Central Power & Light, West Penn Power, Potomac Edison, & Mon Power. Provides electric service to over 6 million customers in OH, PA, NJ, WV, MD, & NY. Acq'd Allegheny Energy 2/11. Electric revenue breakdown by customer class not available. Generating sources: coal, 44%; nuclear, 26%; purchased, 30%. Fuel costs: 43% of revs. '13 reported deprec. rate: 2.6%. Has 15,800 employees. Chairman: George M. Smart. President & CEO: Anthony J. Alexander. COO: Richard R. Grigg. Inc.: OH. Address: 76 South Main Street, Akron, OH 44308-1890. Tel.: 800-736-3402. Internet: www.firstenergycorp.com.

FirstEnergy is active in the regulatory arena. Indeed, the company has about six million customers in five states, plus a large electric transmission system. Jersey Central Power & Light is seeking a $9.1 million rate increase, based on an 11% return on equity. The utility expects a rate order in the first quarter of 2015. FirstEnergy's four utilities in Pennsylvania filed for tariff hikes totaling $415.7 million, based on a 10.9% ROE. Orders are expected in May. The company's utilities in West Virginia reached a regulatory settlement that, if approved, would raise rates by $63 million on February 25th. In Ohio, FirstEnergy proposed a three-year extension of its rate stabilization plan that is similar to the current one, which expires on May 31, 2016. As for transmission, FirstEnergy asked the Federal Energy Regulatory Commission to regulate operations that aren't held within one of its utilities through a forward-looking rate mechanism, effective at the start of 2015. Its allowed ROE on transmission would be 12.38%, which is attractive. All told, the company expects to spend $4.2 billion on transmission from 2014 through 2017.

The focus on regulated businesses is a significant switch from a few years ago. Then, the company's main area of focus was its nonutility operations: merchant generation and retail energy services. However, declining margins in each of these businesses hurt FirstEnergy's profitability to the point where its board of directors cut the dividend, effective with the payment in the first quarter of 2014. The company is still in these businesses, but is shedding energy services customers that are small and weather-sensitive. In addition, the future of a large coal-fired station is in question after its bids in a recent auction were unsuccessful. Still, we expect the competitive operations to contribute to FirstEnergy's profit growth in 2015, and management expects them to generate cash in the next few years. Proposed changes in the PJM power pool would benefit FirstEnergy by raising capacity prices to owners of generating assets.
FirstEnergy stock has a dividend yield that is slightly above the utility norm. Like most utility stocks, 3- to 5-year total return potential is low.
Paul E. Debbas, CFA *November 21, 2014*

(A) Dil. EPS. Excl. nonrec. gain (losses): '05, (28¢); '09, (3¢); '10, (68¢); '11, 33¢; '12, (29¢); '13, ($2.07); '14, (17¢); gains from disc. ops.: '05, 5¢; '13, 4¢; '14, 20¢. '11-'12 EPS don't add due to rounding or chng. in shs. Next egs. due late Feb. (B) Div'ds paid early Mar., June, Sep. & Dec. 5 div'ds decl. in '04, 3 in '13. ■ Div'd reinv. avail. (C) Incl. intang.: In '13: $19.76/sh. (D) In mill. (E) Rate base: Depr. orig. cost. Rates all'd on com. eq.: 9.75%-12.9%; earned on avg. com. eq., '13: 9.3%. Reg. Climate: OH Above Avg.; PA, NJ Avg.; MD, WV Below Avg.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	25
Earnings Predictability	65

Staff/209
Muldoon/20

GREAT PLAINS EN'GY NYSE-GXP

RECENT PRICE	26.95	P/E RATIO	17.1 (Trailing: 17.4; Median: 15.0)	RELATIVE P/E RATIO	0.92	DIV'D YLD	3.7%	VALUE LINE

TIMELINESS 3 Lowered 9/19/14
SAFETY 3 Lowered 12/26/08
TECHNICAL 3 Raised 12/19/14
BETA .85 (1.00 = Market)

High:	32.8	35.7	32.8	32.8	33.4	29.3	20.5	19.9	22.1	22.8	24.9	27.5
Low:	21.4	27.9	27.1	27.1	26.9	15.6	10.2	16.6	16.3	19.5	20.4	23.8

Target Price Range 2017 | 2018 | 2019

2017-19 PROJECTIONS

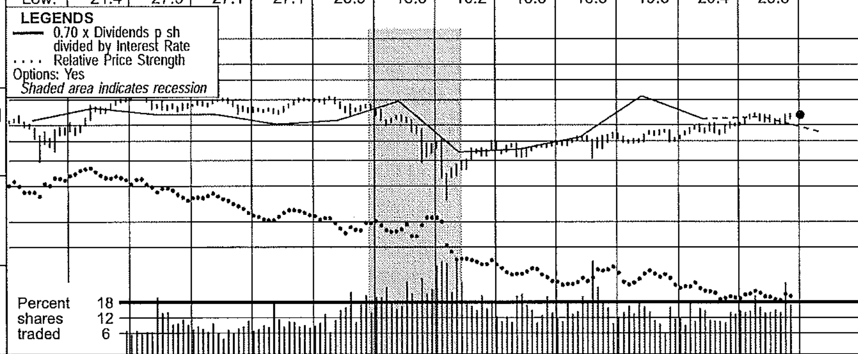
	Price	Gain	Ann'l Total Return
High	30	(+10%)	6%
Low	20	(-25%)	-2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	7	0	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	111	125	124
to Sell	129	117	122
Hld's(000)	116846	118540	117299



64
48
40
32
24
20
16
12
8
6

% TOT. RETURN 11/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	14.3	8.0
3 yr.	39.8	72.4
5 yr.	80.5	119.8

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
15.17	14.50	18.02	23.61	26.91	31.04	33.13	34.85	33.30	37.89	14.00	14.51	16.62	17.03	15.05	15.90	*16.85*	*17.40*	Revenues per sh	*19.50*
4.21	3.63	4.63	4.70	4.40	4.69	4.75	4.54	3.86	4.24	3.09	3.27	4.12	3.51	3.45	4.01	*4.10*	*4.35*	"Cash Flow" per sh	*5.50*
1.89	1.26	2.05	1.59	2.04	2.27	2.46	2.18	1.62	1.86	1.16	1.03	1.53	1.25	1.35	1.62	*1.55*	*1.60*	Earnings per sh A	*2.00*
1.64	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	.83	.83	.84	.86	.88	*.94*	*1.00*	Div'd Decl'd per sh B ■	*1.20*
1.97	2.97	6.67	4.38	1.91	2.19	2.66	4.49	6.05	6.15	8.86	6.49	4.76	3.40	4.01	4.42	*4.95*	*4.50*	Cap'l Spending per sh	*3.75*
14.41	13.97	14.88	12.59	13.58	13.82	15.35	16.37	16.70	18.18	21.39	20.62	21.26	21.74	21.75	22.58	*23.15*	*23.70*	Book Value per sh C	*25.75*
61.91	61.91	61.91	61.91	69.20	69.26	74.37	74.74	80.35	86.23	119.26	135.42	135.71	136.14	153.53	153.87	*154.50*	*155.00*	Common Shs Outst'g D	*156.50*
15.7	20.0	12.4	15.9	11.1	12.2	12.6	14.0	18.3	16.3	20.5	16.0	12.1	16.1	15.5	14.2	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
.82	1.14	.81	.81	.61	.70	.67	.75	.99	.87	1.23	1.07	.77	1.01	.99	.80	*Value Line*		Relative P/E Ratio	*.80*
5.5%	6.6%	6.5%	6.6%	7.3%	6.0%	5.4%	5.5%	5.6%	5.5%	7.0%	5.0%	4.5%	4.1%	4.1%	3.8%	*estimates*		Avg Ann'l Div'd Yield	*4.7%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $3899.2 mill. **Due in 5 Yrs** $1339.1 mill.
LT Debt $3488.1 mill. **LT Interest** $180.3 mill.
(LT interest earned: 2.9x)

Leases, Uncapitalized Annual rentals $15.3 mill.
Pension Assets-12/13 $703.0 mill.
Oblig. $1007.4 mill.
Pfd Stock $39.0 mill. **Pfd Div'd** $1.6 mill.
390,000 shs. 3.80% to 4.50% (all $100 par & cum.), callable from $101 to $103.70.
Common Stock 154,124,361 shs.
as of 11/3/14
MARKET CAP: $4.2 billion (Mid Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
2464.0	2604.9	2675.3	3267.1	1670.1	1965.0	2255.5	2318.0	2309.9	2446.3	*2600*	*2700*	Revenues ($mill)	*3050*
178.8	164.2	127.6	159.2	119.5	135.6	211.7	174.4	199.9	250.2	*240*	*250*	Net Profit ($mill)	*305*
24.1%	18.7%	27.0%	30.7%	34.5%	25.0%	31.7%	32.7%	34.3%	34.0%	*33.0%*	*34.0%*	Income Tax Rate	*35.0%*
2.0%	2.1%	8.4%	10.6%	46.8%	57.0%	25.7%	3.9%	3.3%	10.4%	*12.0%*	*10.0%*	AFUDC % to Net Profit	*2.0%*
44.8%	47.5%	30.6%	40.7%	49.7%	53.2%	50.2%	47.8%	44.9%	50.0%	*49.0%*	*48.5%*	Long-Term Debt Ratio	*43.5%*
53.4%	50.9%	67.5%	57.9%	49.6%	46.2%	49.2%	51.6%	54.4%	49.4%	*50.5%*	*51.0%*	Common Equity Ratio	*56.0%*
2137.1	2403.3	1988.4	2709.8	5146.2	6044.5	5867.6	5741.2	6135.8	7029.1	*7115*	*7215*	Total Capital ($mill)	*7250*
2734.5	2765.6	3066.2	3444.5	6081.3	6651.1	6892.3	7053.5	7402.1	7746.4	*8120*	*8390*	Net Plant ($mill)	*8650*
10.1%	8.2%	7.9%	7.5%	3.5%	3.9%	5.3%	5.0%	5.0%	5.0%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.5%*
15.1%	13.0%	9.2%	9.9%	4.6%	4.8%	7.2%	5.8%	5.9%	7.1%	*6.5%*	*7.0%*	Return on Shr. Equity	*7.5%*
15.5%	13.3%	9.4%	10.1%	4.6%	4.8%	7.3%	5.8%	5.9%	7.2%	*6.5%*	*7.0%*	Return on Com Equity E	*7.5%*
5.1%	3.2%	NMF	.9%	NMF	.9%	3.4%	2.0%	2.2%	3.2%	*2.5%*	*2.5%*	Retained to Com Eq	*3.0%*
68%	76%	104%	91%	NMF	81%	54%	66%	63%	55%	*60%*	*62%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-1.7	-1.8	+.2
Avg. Indust. Use (MWH)	1463	1443	1424
Avg. Indust. Revs. per KWH (¢)	6.11	6.23	6.80
Capacity at Peak (Mw)	6697	6719	NA
Peak Load, Summer (Mw)	5690	5653	NA
Annual Load Factor (%)	50.5	49.6	NA
% Change Customers (avg.)	--	+.2	+.7
Fixed Charge Cov. (%)	211	235	267

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-5.0%	-11.0%	*3.5%*
"Cash Flow"	-2.5%	-.5%	*7.0%*
Earnings	-3.5%	-2.0%	*6.0%*
Dividends	-6.5%	-12.5%	*5.5%*
Book Value	5.0%	3.5%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	492.9	565.1	773.7	486.3	2318.0
2012	479.7	603.6	746.2	480.4	2309.9
2013	542.2	600.3	765.0	538.8	2446.3
2014	585.1	648.4	782.5	*584*	*2600*
2015	*600*	*650*	*850*	*600*	*2700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.01	.31	.91	.01	1.25
2012	d.07	.41	.95	.03	1.35
2013	.17	.41	.93	.11	1.62
2014	.15	.34	.95	*.11*	*1.55*
2015	*.17*	*.35*	*.96*	*.12*	*1.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.2075	.2075	.2075	.2075	.83
2011	.2075	.2075	.2075	.2125	.84
2012	.2125	.2125	.2125	.2175	.86
2013	.2175	.2175	.2175	.23	.88
2014	.23	.23	.23	.245	

BUSINESS: Great Plains Energy Incorporated is a holding company for Kansas City Power & Light and two other subsidiaries, which supply electricity to 831,000 customers in western Missouri (71% of revenues) and eastern Kansas (29%). Acq'd Aquila 7/08. Sold Strategic Energy (energy-marketing subsidiary) in '08. Electric revenue breakdown: residential, 42%; commercial, 40%; industrial, 9%; other, 9%. Generating sources: coal, 75%; nuclear, 11%; wind, 1%; gas & oil, 1%; purchased, 12%. Fuel costs: 27% of revs. '13 reported deprec. rate (utility): 3.0%. Has 3,000 employees. Chairman: Michael J. Chesser. President & CEO: Terry Bassham. Inc.: Missouri. Address: 1200 Main St., Kansas City, Missouri 64105. Tel.: 816-556-2200. Internet: www.greatplainsenergy.com.

One of Great Plains Energy's utility subsidiaries has filed a general rate case. Kansas City Power & Light asked the Missouri regulators for a tariff hike of $120.9 million (15.8%), based on a return of 10.3% on a common-equity ratio of 50.36%. The utility is seeking to place environmental and nuclear upgrades in the rate base and recover higher expenses for property taxes and electric transmission. KCP&L also wants the commission to institute a fuel adjustment clause that would include transmission costs, and is requesting other regulatory mechanisms that would track things such as property taxes. (KCP&L already has a property-tax rider in Kansas.) This would reduce regulatory lag, which has been a big problem for the company for several years and has resulted in low returns on equity. New rates are expected to go into effect in late September of 2015. KCP&L will file a rate case in Kansas in early January, with new tariffs taking effect in October. Part of the aforementioned environmental upgrade is already included in the rate base, so this requested increase won't be as large as the one in Missouri.

Earnings probably won't make much progress until 2016. That will be the first full year after KCP&L's rate increases. Until the fourth quarter of 2015, the utility will continue to be affected by regulatory lag. We have trimmed our 2014 and 2015 earnings estimates by a nickel a share each year. Our revised 2014 estimate of $1.55 a share is within the company's targeted range of $1.52-$1.62.

The board of directors raised the dividend this quarter. The quarterly disbursement was boosted by $0.015 a share (6.5%), slightly more than we had estimated. This was a bit above Great Plains' targeted dividend growth rate of 4%-6%. The company wants to maintain a payout ratio of 55%-70% through 2016, and 60%-70% thereafter. Note that the company's cash flow benefits from tax-loss carryforwards.

The dividend yield, following the increase, is somewhat above the utility mean. Like most electric company stocks, the recent price is within our 2017-2019 Target Price Range, so 3- to 5-year total return potential is unimpressive.

Paul E. Debbas, CFA *December 19, 2014*

(A) Dil. EPS. Excl. nonrec. gains (losses): '00, 49¢; '01, ($2.01); '02, (5¢); '03, 29¢; '04, (7¢); '09, 12¢; gain (losses) on disc. ops.: '03, (13¢); '04, 10¢; '05, (3¢); '08, 35¢. '11-'12 EPS don't add due to change in shs. or rounding. Next earnings report due early Feb. (B) Div'ds historically paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '13: $6.62/sh. (D) In mill. (E) Rate base: Fair value. Rate all'd on com. eq. in MO in '13: 9.7%; in KS in '13: 9.5%; earned on avg. com. eq., '13: 7.3%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	5
Earnings Predictability	70

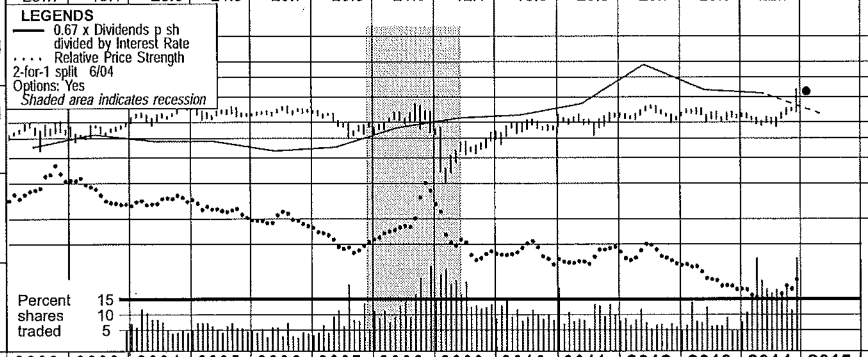
HAWAIIAN ELECTRIC NYSE-HE

RECENT PRICE 34.14 | P/E RATIO 21.1 (Trailing: 20.0 Median: 19.0) | RELATIVE P/E RATIO 1.15 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS – Suspended 12/12/14
SAFETY 2 Raised 11/2/12
TECHNICAL – Suspended 12/12/14
BETA .80 (1.00 = Market)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
High:	24.0	29.5	29.8	28.9	27.5	29.8	22.7	25.0	26.8	29.2	28.3	35.0
Low:	19.1	23.0	24.6	25.7	20.3	21.0	12.1	18.6	20.6	23.7	23.8	22.7

LEGENDS
— 0.67 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 6/04
Options: Yes
Shaded area indicates recession



Target Price Range 2017 2018 2019

2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(-10%)	*1%*
Low	20	(-40%)	*-7%*

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	1	0	0	1	0	0	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	109	118	104
to Sell	75	81	107
Hld's(000)	45986	52741	53079

Percent shares traded 15 10 5

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	34.9	6.9
3 yr.	45.9	73.7
5 yr.	105.6	107.3

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
23.12	23.64	26.05	24.26	22.46	23.49	23.85	27.36	30.21	30.40	35.56	24.96	28.14	33.76	34.46	31.98	*31.05*	*29.05*	Revenues per sh	*33.75*
3.23	3.35	3.08	3.33	3.52	3.54	3.09	3.22	3.19	3.01	2.72	2.59	2.88	3.18	3.28	3.22	*3.35*	*3.40*	"Cash Flow" per sh	*4.00*
1.48	1.45	1.27	1.60	1.62	1.58	1.36	1.46	1.33	1.11	1.07	.91	1.21	1.44	1.67	1.62	*1.65*	*1.65*	Earnings per sh A	*2.00*
1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	*1.24*	Div'd Decl'd per sh B ■	*1.30*
2.60	2.09	2.04	1.77	1.74	2.15	2.66	2.76	2.58	2.62	3.12	3.29	1.92	2.45	3.32	3.49	*3.50*	*3.45*	Cap'l Spending per sh	*4.50*
12.87	13.16	12.72	13.06	14.21	14.36	15.01	15.02	13.44	15.29	15.35	15.58	15.67	15.95	16.28	17.06	*17.60*	*18.15*	Book Value per sh C	*20.50*
64.23	64.43	65.98	71.20	73.62	75.84	80.69	80.98	81.46	83.43	90.52	92.52	94.69	96.04	97.93	101.26	*103.00*	*105.00*	Common Shs Outst'g D	*111.00*
13.4	12.1	12.9	11.8	13.5	13.8	19.2	18.3	20.3	21.6	23.2	19.8	18.6	17.1	15.8	16.2	*15.8*		Avg Ann'l P/E Ratio	*12.5*
.70	.69	.84	.60	.74	.79	1.01	.97	1.10	1.15	1.40	1.32	1.18	1.07	1.01	.91	*.80*		Relative P/E Ratio	*.80*
6.2%	7.1%	7.5%	6.6%	5.7%	5.7%	4.8%	4.6%	4.6%	5.2%	5.0%	6.9%	5.5%	5.0%	4.7%	4.7%	4.8%		Avg Ann'l Div'd Yield	*5.1%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $1668.5 mill. **Due in 5 Yrs** $421.4 mill.
LT Debt $1506.5 mill. **LT Interest** $69.9 mill.
Incl. $50 mill. 6.5% oblig. pfd. sec. of trust subsid.
(LT interest earned: 4.4x)
Leases, Uncapitalized Annual rentals $18.0 mill.
Pension Assets-12/13 $1186.7 mill. **Oblig.** $1446.3 mill.
Pfd Stock $34.3 mill. **Pfd Div'd** $2.0 mill.
1,114,657 shs. 4¼% to 5¼%, $20 par. call. $20 to $21; 120,000 shs. 7⅝%, $100 par. call. $100. Sinking fund ends 2018.
Common Stock 102,562,464 shs. **as of 10/31/14**
MARKET CAP: $3.5 billion (Mid Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
1924.1	2215.6	2460.9	2536.4	3218.9	2309.6	2665.0	3242.3	3375.0	3238.5	*3200*	*3050*	Revenues ($mill)	*3750*
109.6	120.3	109.9	93.6	92.2	84.9	115.4	140.1	164.9	163.4	*170*	*175*	Net Profit ($mill)	*235*
45.8%	36.4%	36.5%	35.4%	34.7%	34.1%	37.0%	35.1%	35.9%	34.0%	*33.0%*	*33.0%*	Income Tax Rate	*31.5%*
7.6%	5.9%	8.4%	8.3%	14.2%	20.6%	7.4%	6.0%	6.9%	4.8%	*17.0%*	*16.0%*	AFUDC % to Net Profit	*17.0%*
47.6%	45.2%	49.9%	47.6%	46.0%	48.0%	44.5%	44.9%	45.7%	44.0%	*45.0%*	*46.5%*	Long-Term Debt Ratio	*50.0%*
51.0%	53.3%	48.6%	51.0%	52.7%	50.7%	54.3%	53.9%	53.1%	55.0%	*54.0%*	*52.5%*	Common Equity Ratio	*49.0%*
2375.1	2283.9	2252.7	2501.8	2635.2	2840.8	2732.9	2841.3	3001.0	3142.9	*3355*	*3630*	Total Capital ($mill)	*4625*
2422.3	2542.8	2647.5	2743.4	2907.4	3088.6	3165.9	3334.5	3594.8	3858.9	*4045*	*4220*	Net Plant ($mill)	*4950*
6.0%	6.8%	6.4%	5.2%	4.7%	4.3%	5.6%	6.2%	6.7%	6.4%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
8.8%	9.6%	9.7%	7.1%	6.5%	5.8%	7.6%	8.9%	10.1%	9.3%	*9.0%*	*9.0%*	Return on Shr. Equity	*10.0%*
8.9%	9.7%	9.9%	7.2%	6.5%	5.8%	7.7%	9.0%	10.2%	9.4%	*9.5%*	*9.0%*	Return on Com Equity E	*10.0%*
1.1%	1.5%	.7%	.8%	.5%	NMF	1.4%	2.1%	4.2%	3.7%	*2.5%*	*2.0%*	Retained to Com Eq	*4.0%*
87%	85%	93%	89%	93%	116%	82%	78%	59%	61%	*75%*	*75%*	All Div'ds to Net Prof F	*62%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-.5	-3.5	-1.5
Avg. Indust. Use (MWH)	6284	6119	6112
Avg. Indust. Revs. per KWH (¢)	27.89	30.35	29.31
Capacity at Yearend (Mw)	2327	2332	2354
Peak Load, Winter (Mw)	1530	1535	1535
Annual Load Factor (%)	74.8	72.1	71.0
% Change Customers (yr-end)	+.3	+.5	+.8
Fixed Charge Cov. (%)	337	396	398

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	3.5%	1.0%	*Nil*
"Cash Flow"	-.5%	1.5%	*3.5%*
Earnings	--	6.0%	*4.0%*
Dividends	--	--	*1.0%*
Book Value	1.5%	2.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	710.6	794.3	886.4	851.0	3242.3
2012	814.9	854.3	867.7	838.1	3375.0
2013	784.1	796.7	831.2	826.5	3238.5
2014	783.7	798.7	867.1	*750.5*	*3200*
2015	*750*	*750*	*800*	*750*	*3050*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.30	.28	.50	.36	1.44
2012	.40	.40	.49	.38	1.67
2013	.34	.41	.48	.39	1.62
2014	.45	.41	.46	*.33*	*1.65*
2015	*.39*	*.44*	*.46*	*.36*	*1.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.31	.31	.31	.31	1.24
2012	.31	.31	.31	.31	1.24
2013	.31	.31	.31	.31	1.24
2014	.31	.31	.31	.31	1.24
2015					

BUSINESS: Hawaiian Electric Industries, Inc. is the parent company of Hawaiian Electric Company, Inc. (HECO) & American Savings Bank (ASB). HECO & its subs., Maui Electric Co. (MECO) & Hawaii Electric Light Co. (HELCO), supply electricity to 452,000 customers on O'ahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Disc. int'l power sub. in '01. Elec. rev. breakdown: res'l, 30%; comm'l, 35%; large light & power, 34%; other, 1%. Generating sources: oil, 56%; purchased, 44%. Fuel costs: 60% of revs. '13 reported depr. rate (util.): 3.1%. Has 4,000 empls. Chairman: Jeffrey N. Watanabe. Pres. & CEO: Constance H. Lau. Inc.: HI. Address: 1001 Bishop St., Suite 2900, Honolulu, HI 96808-0730. Tel.: 808-543-5662. Internet: www.hei.com.

Hawaiian Electric Industries has agreed to be acquired by NextEra Energy. NextEra is buying HEI's three utility subsidiaries. For each of their shares, HEI stockholders would receive 0.2413 of a share of NextEra stock (valued at $26.28); a $0.50-a-share special dividend; and a share of American Savings Bank. ASB would be spun off into a publicly traded company, subject to completion of the utility takeover. HEI estimates that the value of ASB stock would be $8.00 a share. All told, the compensation to HEI stockholders would amount to $34.78 a share. NextEra would also assume a tax liability estimated at $1.60 a share stemming from the ASB spinoff. All of the compensation except the special dividend would be tax-free to HEI stockholders, who will vote on the deal. The transaction also requires the approval of the Hawaii Public Utilities Commission (PUC) and the Federal Energy Regulatory Commission. The companies expect the deal to close by late 2015.

What should HEI stockholders do? This depends on tax considerations. With the price of HEI stock just 2% below the value of NextEra's generous offer, there is little upside potential unless the price of NextEra stock continues to rise. However, selling the stock would create a capital gain. The Timeliness rank of HEI stock is suspended due to the takeover agreement.

The transformation of utilities in Hawaii is ongoing. Last year, the PUC directed the company to put forth a proposal to increase the use of renewable energy and address the problem of high oil prices. Although oil prices have come down considerably since then (and customers had seen their bills decline by 20% by the end of 2014), the state still wants to reduce its dependence on foreign sources of energy. The rates customers are paying for their power are still well above the national average, even with lower oil prices. Meanwhile, the company wants to increase the monthly fixed charge for residential ratepayers. As more customers have placed solar panels on their buildings, nonsolar customers are subsidizing solar users.

We have trimmed our 2015 earnings estimate by $0.05 a share. HEI will likely incur some merger-related costs stemming from the deal with NextEra.

Paul E. Debbas, CFA *January 30, 2015*

(A) Dil. EPS. Excl. gains (losses) from disc. ops.: '00, (56¢); '01, (36¢); '03, (5¢); '04, 2¢; '05, (1¢); nonrec. gain (losses): '05, 11¢; '07, (9¢); '12, (25¢). Next earnings report due mid-Feb. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '13: $5.81/sh. (D) In mill., adj. for split. (E) Rate base: Orig. cost. Rate allowed on com. eq. in '11: HECO, 10%; in '12: HELCO, 10%; in '13: MECO, 9%; earned on avg. com. eq., '13: 9.7%. Regul. Climate: Avg. (F) Excl. div'ds paid through reinvest. plan.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	35
Earnings Predictability	75

IDACORP, INC. NYSE-IDA

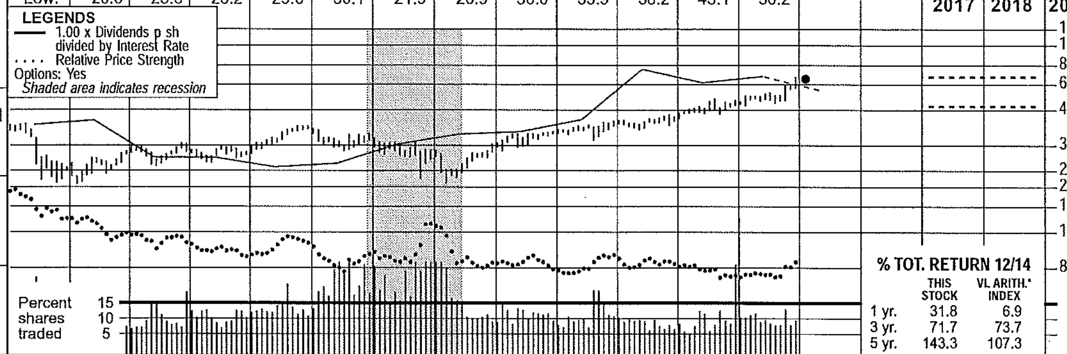
RECENT PRICE **68.20** | P/E RATIO **18.6** (Trailing: 18.3 / Median: 14.0) | RELATIVE P/E RATIO **1.01** | DIV'D YLD **2.8%** | **VALUE LINE**

TIMELINESS 3 Lowered 12/12/14
SAFETY 2 Raised 8/2/13
TECHNICAL 3 Raised 1/2/15
BETA .80 (1.00 = Market)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
High:					30.2	32.9	32.1	40.2	39.2	35.1	32.8	37.8	42.7	45.7	54.7	70.1	
Low:					20.6	25.3	26.2	29.0	30.1	21.9	20.9	30.0	33.9	38.2	43.1	50.2	

Target Price Range

2017	2018	2019



% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	31.8	6.9
3 yr.	71.7	73.7
5 yr.	143.3	107.3

2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(5%)	3%
Low	50	(-25%)	-4%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	1	0	0	0	0
Options	2	0	0	0	0	0	0	0	0
to Sell	2	3	0	2	2	0	4	1	1

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	92	86	70
to Sell	84	106	106
Hld's(000)	37877	36553	36655

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
29.83	17.50	27.10	150.10	24.43	20.41	20.00	20.15	21.23	19.51	20.47	21.92	20.97	20.55	21.55	24.81	24.50	25.10	Revenues per sh	27.10
4.69	4.50	5.63	5.63	4.08	3.50	4.12	3.87	4.58	4.11	4.27	5.07	5.23	5.74	5.84	6.21	6.25	6.40	"Cash Flow" per sh	6.90
2.37	2.43	3.50	3.35	1.63	.96	1.90	1.75	2.35	1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.75	3.60	Earnings per sh A	3.75
1.86	1.86	1.86	1.86	1.86	1.70	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.90	Div'd Decl'd per sh B† ■	2.20
2.37	2.95	3.73	4.78	3.53	3.89	4.73	4.53	5.16	6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.70	6.45	Cap'l Spending per sh	12.95
19.42	20.02	21.82	23.15	23.01	22.54	23.88	24.04	25.77	26.79	27.76	29.17	31.01	33.19	35.07	36.84	38.60	40.30	Book Value per sh C	44.90
37.61	37.61	37.61	37.63	38.02	38.34	42.22	42.66	43.63	45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.20	50.20	Common Shs Outst'g D	50.20
14.4	12.7	10.9	11.4	18.9	26.5	15.5	16.7	15.1	18.2	13.9	10.2	11.8	11.5	12.4	13.4	15.1		Avg Ann'l P/E Ratio	16.0
.75	.72	.71	.58	1.03	1.51	.82	.89	.82	.97	.84	.68	.75	.72	.79	.75	.79		Relative P/E Ratio	1.00
5.4%	6.0%	4.9%	4.9%	6.0%	6.7%	4.1%	4.1%	3.4%	3.5%	4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%		Avg Ann'l Div'd Yield	3.6%
						844.5	859.5	926.3	879.4	960.4	1049.8	1036.0	1026.8	1080.7	1246.2	1250	1260	Revenues ($mill)	1360
						77.8	63.7	100.1	82.3	98.4	124.4	142.5	166.9	168.9	182.4	180	180	Net Profit ($mill)	190
						--	16.9%	13.3%	14.3%	16.3%	15.2%	--	--	13.4%	28.3%	24.0%	25.0%	Income Tax Rate	30.0%
						3.9%	4.7%	4.0%	9.7%	10.2%	10.5%	19.7%	22.8%	7.1%	4.2%	7.5%	8.0%	AFUDC % to Net Profit	9.5%
						49.3%	50.0%	45.2%	48.9%	47.6%	50.2%	49.3%	45.6%	45.5%	46.6%	48.0%	48.0%	Long-Term Debt Ratio	48.5%
						50.7%	50.0%	54.8%	51.1%	52.4%	49.8%	50.7%	54.4%	54.5%	53.4%	52.0%	52.0%	Common Equity Ratio	51.5%
						1987.8	2048.8	2052.8	2364.2	2485.9	2807.1	3020.4	3045.2	3225.4	3465.9	3715	3890	Total Capital ($mill)	4415
						2209.5	2314.3	2419.1	2616.6	2758.2	2917.0	3161.4	3406.6	3536.0	3665.0	3900	4095	Net Plant ($mill)	4740
						5.3%	4.5%	6.2%	4.7%	5.3%	5.7%	6.0%	6.7%	6.5%	6.4%	6.0%	5.5%	Return on Total Cap'l	5.0%
						7.7%	6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.0%	9.0%	Return on Shr. Equity	8.5%
						7.2%	6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.0%	9.0%	Return on Com Equity E	8.5%
						2.7%	1.3%	4.3%	2.4%	3.4%	4.8%	5.5%	6.5%	5.7%	5.6%	4.5%	4.0%	Retained to Com Eq	3.5%
						65%	80%	51%	64%	55%	46%	41%	36%	41%	43%	51%	53%	All Div'ds to Net Prof	58%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $1615.4 mill. **Due in 5 Yrs** $124.3 mill.
LT Debt $1614.3 mill. **LT Interest** $81.5 mill.
(LT interest earned: 6.3x)

Pension Assets-12/13 $545.1 mill.
Oblig. $695.1 mill.

Pfd Stock None

Common Stock 50,268,748 shs.
as of 10/24/14

MARKET CAP: $3.4 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+1.6	+2.6	+3.8
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	4.54	4.63	5.21
Capacity at Peak (Mw)	N/A	N/A	N/A
Peak Load, Summer (Mw)	2973	3245	3407
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+.7	+1.1	+1.5
Fixed Charge Cov. (%)	194	283	329

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-10.0%	2.0%	3.5%
"Cash Flow"	3.0%	6.5%	2.5%
Earnings	5.5%	10.0%	1.5%
Dividends	-2.5%	3.0%	8.0%
Book Value	4.5%	5.5%	4.0%

Cal-endar	QUARTERLY REVENUES($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	251.5	235.0	309.6	230.7	1026.8
2012	241.1	254.7	334.0	250.9	1080.7
2013	264.9	303.9	381.1	296.3	1246.2
2014	292.7	317.7	382.2	257.4	1250
2015	290	305	385	280	1260

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.60	.42	2.16	.18	3.36
2012	.50	.71	1.84	.33	3.37
2013	.70	.93	1.46	.55	3.64
2014	.55	.89	1.73	.58	3.75
2015	.60	.75	1.85	.40	3.60

Cal-endar	QUARTERLY DIVIDENDS PAID B† ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.30	.30	.30	.30	1.20
2012	.33	.33	.33	.38	1.37
2013	.38	.38	.38	.43	1.57
2014	.43	.43	.43	.47	1.76
2015					

BUSINESS: IDACORP, Inc. is the holding company for Idaho Power, a utility that operates 17 hydroelectric generation developments, 3 natural gas-fired plants, and partly owns three coal plants across Idaho, Oregon, Wyoming, and Nevada. Service territory covers 24,000 square miles, serving 501,000 business customers. Sells electricity in Idaho (95% of revenues) and Oregon (5%). Revenue breakdown: residential, 40%; commercial, 22%; industrial, 14%; other, 24%. Fuel sources: hydro, 45%; thermal, 34%; purchased power, 21%. '13 depr rate: 2.4%. Has 2,067 employees. Chairman: Robert A. Tinstman. President & CEO: Darrel T. Anderson. Incorp: Idaho. Address: 1221 W. Idaho St., Boise, ID 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

We are raising our 2014 share-net estimate for IDACORP. Third-quarter results were above our expectations. Better than expected results were due to slightly improved weather in the September period. Customer growth has also aided sales volume, as it has helped to offset lower usage among the company's residential and irrigation customer categories. However, earnings in the September period were primarily impacted by lower income tax expense. This was due to a tax method change related to Idaho Power's capitalized repairs reduction. IDACORP recently raised its guidance for 2014 to reflect the lower tax expense. The company expects 2014 earnings to be in the range of $3.70 to $3.80 per share, higher than the previous guidance of $3.50 to $3.65 per share. In accordance, we have raised our 2014 estimate to $3.75 per share. Looking ahead, the method change is expected to result in a small amount of continued benefit, depending on the nature of annual capital additions at Idaho Power. IDACORP expects more clarity on this in the next quarter.

Idaho Power is currently working on its 2015 Integrated Resource Plan. The plan is expected to indicate a modest increase in the average and peak load growth from the company's earlier IRP in 2013. The completed Integrated Resource Plan is expected to be filed with the Idaho Public Utility Commission by June 2015.

A dividend hike is likely in 2015. The company's dividend policy seeks to maintain a payout ratio between 50% and 60%. The board of directors recently increased the dividend payout in September, 2014 by 9.3%. The dividend should continue to see an improvement until IDACORP reaches the upper end of the payout range.

These shares do not stand out at this juncture. Based on the stock's current Timeliness rank, it is expected to be an average performer over the next six to 12 months. However, appreciation potential over the next 3- to 5-year period is limited, as the stock price is already at the top of our three- to five-year Target Price Range. Additionally, although further dividend increases are likely, the company's current dividend yield is presently below the average yield of 3.3% for electric utilities.

Saumya Ajila *January 30, 2015*

(A) EPS diluted. Excl. nonrecurring gains (loss): '00, 22¢; '03, 26¢; '05, (24¢); '06, 17¢. Egs. may not sum to total due to rounding. Next earnings report due in late February. (B) Div'ds historically paid in late Feb., May, Aug., and late Nov. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred debits. In '13: $21.06/sh. (D) In mill. (E) Rate Base: Net original cost. Rate allowed on com. eq. in Idaho in '11: 9.5%-10.5%; earned on avg. system com. eq., '13: 9.6%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	80
Earnings Predictability	90

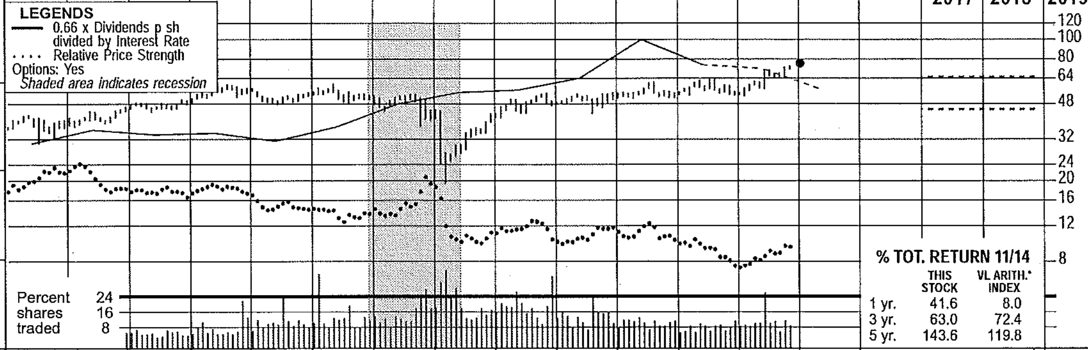
INTEGRYS ENERGY NYSE-TEG

RECENT PRICE **76.03** | P/E RATIO **25.0** (Trailing: 18.7 / Median: 15.0) | RELATIVE P/E RATIO **1.35** | DIV'D YLD **3.6%** | **VALUE LINE**

High:	46.8	50.5	60.0	57.8	60.6	53.9	45.1	54.4	54.6	61.9	63.6	76.2
Low:	36.8	43.5	47.7	47.4	48.1	36.9	19.4	40.5	42.8	50.8	52.6	52.1

TIMELINESS – Suspended 7/4/14
SAFETY **2** Raised 6/24/11
TECHNICAL – Suspended 7/4/14
BETA .80 (1.00 = Market)

LEGENDS
— 0.66 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2017 | 2018 | 2019

2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(-15%)	Nil
Low	45	(-40%)	-7%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	10	0	1	0	3	0	1	5
to Sell	0	0	2	1	0	3	0	2	5

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	168	140	138
to Sell	142	170	148
Hld's(000)	42754	43525	44422

Percent shares traded 24 16 8

% TOT. RETURN 11/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	41.6	8.0
3 yr.	63.0	72.4
5 yr.	143.6	119.8

Integrys Energy Group was created as a holding company on February 21, 2007 to oversee the entire operations of the recently merged WPS Resources and Peoples Energy. WPS acquired Peoples in an agreement under which each common share of Peoples was converted into .825 share of WPS common. The combination took the new name of Integrys Energy Group. All data on this page prior to 2/21/07 are for WPS Resources only.

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
131.26	173.37	160.01	135.44	184.86	98.71	67.27	60.44	54.07	70.92	*82.50*	*48.15*	Revenues per sh	*53.75*
6.98	7.40	6.33	5.19	4.69	5.34	6.70	6.13	6.95	7.72	*6.85*	*6.75*	"Cash Flow" per sh	*8.00*
4.07	4.09	3.51	2.48	1.58	2.28	3.24	2.88	3.67	4.33	*3.35*	*3.15*	Earnings per sh A	*3.75*
2.20	2.24	2.28	2.56	2.68	2.72	2.72	2.72	2.72	2.72	*2.72*	*2.72*	Div'd Decl'd per sh B ■	*2.72*
7.78	10.31	7.94	5.17	7.01	5.85	3.35	4.00	7.63	8.42	*13.15*	*11.55*	Cap'l Spending per sh	*11.25*
29.30	32.47	35.61	42.58	40.79	37.62	37.57	38.01	38.84	41.05	*42.00*	*42.45*	Book Value per sh C	*45.00*
37.26	40.16	43.06	75.99	75.99	75.98	77.35	77.91	77.90	79.45	*80.00*	*80.00*	Common Shs Outst'g D	*80.00*
11.5	13.4	14.7	21.4	30.7	14.8	14.7	17.5	14.8	13.3	Bold figures are	Value Line	Avg Ann'l P/E Ratio	*14.5*
.61	.71	.79	1.14	1.85	.99	.94	1.10	.94	.75	estimates		Relative P/E Ratio	*.95*
4.7%	4.1%	4.4%	4.8%	5.5%	8.1%	5.7%	5.4%	5.0%	4.7%			Avg Ann'l Div'd Yield	*5.0%*
4890.6	6962.7	6890.7	10292	14048	7499.8	5203.2	4708.7	4212.4	5634.6	*6600*	*3850*	Revenues ($mill)	*4300*
156.2	157.4	151.6	181.1	124.8	178.2	255.9	230.9	294.2	350.1	*270*	*255*	Net Profit ($mill)	*310*
16.1%	22.9%	22.9%	32.2%	29.1%	41.5%	40.4%	36.7%	33.8%	37.6%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
1.7%	1.0%	.5%	.7%	5.8%	4.5%	.7%	.4%	1.3%	4.3%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
43.1%	39.0%	44.8%	40.8%	42.1%	45.1%	42.2%	38.3%	38.6%	47.2%	*46.5%*	*47.0%*	Long-Term Debt Ratio	*48.5%*
54.4%	58.7%	53.4%	58.3%	57.0%	53.9%	56.8%	60.6%	60.4%	52.0%	*53.0%*	*52.0%*	Common Equity Ratio	*50.5%*
2008.6	2222.4	2871.9	5552.0	5438.7	5304.4	5118.5	4884.5	5008.6	6268.6	*6365*	*6530*	Total Capital ($mill)	*7125*
2002.6	2049.4	2534.8	4463.8	4773.3	4945.1	5013.4	5199.1	5501.9	6410.5	*6990*	*7625*	Net Plant ($mill)	*9500*
8.8%	8.0%	6.4%	4.5%	3.5%	4.6%	6.2%	5.9%	6.9%	6.5%	*5.5%*	*5.0%*	Return on Total Cap'l	*5.5%*
13.7%	11.6%	9.6%	5.5%	4.0%	6.1%	8.7%	7.7%	9.6%	10.6%	*8.0%*	*7.5%*	Return on Shr. Equity	*8.5%*
14.0%	11.8%	9.7%	5.5%	3.9%	6.1%	8.7%	7.7%	9.6%	10.6%	*8.0%*	*7.5%*	Return on Com Equity E	*8.5%*
6.6%	5.3%	3.4%	--	NMF	NMF	2.3%	.7%	2.6%	4.4%	*1.5%*	*1.0%*	Retained to Com Eq	*2.5%*
54%	56%	65%	99%	NMF	118%	74%	91%	73%	59%	*81%*	*86%*	All Div'ds to Net Prof	*71%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $3348.8 mill. **Due in 5 Yrs** $780.7 mill.
LT Debt $2956.3 mill. **LT Interest** $147.8 mill.
(LT interest earned: 4.9x)
Leases, Uncapitalized Annual rentals $6.7 mill.
Pension Assets-12/13 $1527.7 mill. **Oblig.** $1641.7 mill.
Pfd Stock $51.1 mill. **Pfd Div'd** $3.1 mill.
510,626 shs. 5.00% to 6.88%, callable $101 to $107.50; sinking fund began 11/1/79. All cumulative, $100 par.
Common Stock 79,963,091 shs.
as of 11/4/14
MARKET CAP: $6.1 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+.9	+.2	-.4
Avg. C & I Use (KWH)	NA	NA	NA
Avg. C & I Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	3312	3173	3344
Peak Load, Summer (Mw)	2465	2347	2400
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.4	+.4	+.4
Fixed Charge Cov. (%)	302	367	410

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-4.5%	-17.5%	*NMF*
"Cash Flow"	2.0%	5.0%	*2.5%*
Earnings	3.0%	7.5%	*.5%*
Dividends	2.5%	1.5%	*Nil*
Book Value	4.5%	--	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	1627.1	1010.8	938.7	1132.1	4708.7
2012	1247.9	839.6	927.7	1197.2	4212.4
2013	1678.2	1116.0	1129.7	1710.7	5634.6
2014	2925	1433	1188	*1054*	*6600*
2015	*1250*	*850*	*650*	*1100*	*3850*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	1.56	.38	.47	.48	2.88
2012	1.24	.65	.93	.86	3.67
2013	2.29	d.06	.47	1.63	4.33
2014	1.89	.17	.37	*.92*	*3.35*
2015	*1.35*	*.40*	*.45*	*.95*	*3.15*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.68	.68	.68	.68	2.72
2011	.68	.68	.68	.68	2.72
2012	.68	.68	.68	.68	2.72
2013	.68	.68	.68	.68	2.72
2014	.68	.68	.68	.68	

BUSINESS: Integrys Energy Group, Inc. is a holding company for Wisconsin Public Service, Peoples Gas, and four other utility subsidiaries. Has 497,000 electric customers in WI and MI, 1.7 million gas customers in WI, IL, MN, and MI. Also has retail electric and gas marketing ops. in the Northeast and Midwest. Elec. rev. breakdown: residential, 29%; small commercial & industrial, 29%; large commercial & industrial, 19%; other, 23%. Generating sources: coal, 53%; gas, 9%; wind, 2%; hydro, 2%; purch., 34%. Fuel costs: 62% of revs. '13 depr. rates (utility): 1.9%-3.3%. Has 4,900 empls. Chairman & CEO: Charles A. Schrock. Pres. & COO: Lawrence T. Borgard. Inc.: WI. Address: 130 East Randolph St., Chicago, IL 60601-6207. Tel.: 312-228-5400. Internet: www.integrysgroup.com.

Integrys Energy shareholders have approved the sale of the company to Wisconsin Energy. The agreement calls for Integrys holders to receive $18.58 in cash and 1.128 shares of Wisconsin Energy stock for each of their shares, making the value of the deal $76.05 a share at Wisconsin Energy's recent price. The deal requires the approval of the regulatory commissions in Wisconsin, Illinois, and Michigan (and perhaps Minnesota, too), plus the Federal Energy Regulatory Commission. The company expects the transaction to close in the summer of 2015. Due to the takeover agreement, the Timeliness rank of Integrys stock is suspended.

We think Integrys holders should sell their stock on the open market. The recent price is almost equal to the value of the deal, leaving no upside potential for stockholders unless the price of Wisconsin Energy stock continues to rise. On the other hand, the stock price will likely drop sharply if the transaction falls through.

Integrys has completed the sale of its retail energy services business. Heavy competition has squeezed margins here. The company received over $300 million. Integrys will report this as a discontinued operation effective with the fourth-quarter earnings release, but we haven't yet restated results for the first three quarters of 2014. This segment earned $0.33 a share in the first nine months of 2014 (excluding a goodwill impairment and including some small assets that Integrys is retaining). Note that our earnings presentation includes costs related to the buyout, estimated at $0.09 a share in 2014.

Some of Integrys' utilities are awaiting rate orders. A gas rate hike of $7.6 million was granted in Minnesota, with an allowed return on equity of 9.35%. Wisconsin Public Service should soon get a written order calling for an electric rate increase of $25 million and a gas rate decrease of $15 million, based on a 10.2% ROE. The utility has asked the Michigan regulators for a $5.7 million electric tariff hike, based on a 10.6% ROE. Interim rates should take effect in mid-April, with a final order in mid-October. The company's two gas utilities in Illinois are seeking a total of $107.0 million, based on a 10.25% ROE. A decision is expected next month.

Paul E. Debbas, CFA *December 19, 2014*

(A) Dil. EPS. Excl. nonrecur. gain (losses): '09, ($3.24); '10, (41¢); '14, 56¢ net; gains (losses) from disc. ops.: '07, $1.02; '08, 6¢; '09, 4¢; '11, (1¢); '12, (12¢); '13, 6¢; '14, 1¢. '11 & '12 EPS don't add due to rounding. Next egs. report due late Feb. (B) Div'ds histor. paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '13: $26.11/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in WI in '13: 10.3%; in IL in '13: 9.28%; in MN in '14: 9.35%; earn. on avg. com. eq, '13: 10.8%. Reg. Clim.: WI, Above Avg.; IL, Below Avg.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	40
Earnings Predictability	45

ITC HOLDINGS CORP. NYSE-ITC

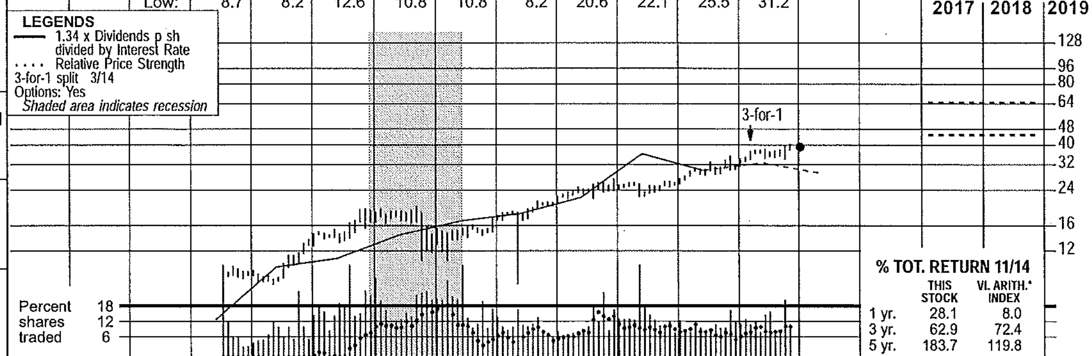
RECENT PRICE **39.12** | P/E RATIO **19.6** (Trailing: 22.7 / Median: NMF) | RELATIVE P/E RATIO **1.06** | DIV'D YLD **1.8%** | **VALUE LINE**

TIMELINESS 2 Raised 9/26/14
SAFETY 2 Raised 6/24/11
TECHNICAL 5 Lowered 12/12/14
BETA .65 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
High:	10.1	13.7	19.5	20.0	17.6	21.3	27.3	26.6	35.6	40.7
Low:	8.7	8.2	12.6	10.8	10.8	8.2	20.6	22.1	25.5	31.2

Target Price Range

2017	2018	2019



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+65%)	15%
Low	45	(+15%)	6%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	4	3	0	1	1
to Sell	0	0	0	0	4	4	0	2	1

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	161	164	147
to Sell	126	141	156
Hld's(000)	146632	143907	141050

% TOT. RETURN 11/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	28.1	8.0
3 yr.	62.9	72.4
5 yr.	183.7	119.8

ITC Holdings was incorporated in the state of Michigan in 2002 for the purpose of acquiring ITC Transmission, which was a subsidiary of The Detroit Edison Company. The acquisition was completed in 2003. ITC Holdings went public on July 26, 2005, via an initial public offering of 37.5 million shares at $7.67 a share (adjusted for split). The deal was underwritten by Lehman Brothers, Morgan Stanley, and Credit Suisse First Boston.

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
1.37	2.06	1.76	3.31	4.15	4.13	4.58	4.92	5.30	5.98	*6.95*	*7.75*	Revenues per sh	*10.50*
.35	.68	.58	1.10	1.37	1.44	1.53	1.73	1.88	2.24	*2.70*	*3.15*	"Cash Flow" per sh	*4.50*
.03	.35	.31	.56	.73	.86	.95	1.10	1.20	1.47	*1.75*	*2.10*	Earnings per sh A	*3.00*
--	.18	.36	.38	.40	.42	.44	.46	.49	.54	*.61*	*.69*	Div'd Decl'd per sh B ■ †	*1.00*
.83	1.19	1.32	2.23	2.70	2.69	2.55	3.62	5.12	5.22	*5.45*	*5.20*	Cap'l Spending per sh	*6.50*
2.14	2.64	4.18	4.37	6.24	6.73	7.34	8.18	9.03	10.25	*10.60*	*11.60*	Book Value per sh C	*17.25*
92.04	99.69	127.19	128.75	148.96	150.25	152.15	153.97	156.75	157.50	*154.50*	*152.50*	Common Shs Outst'g D	*155.50*
--	26.3	33.0	27.6	23.2	17.1	20.0	21.4	20.7	20.4	*Bold figures are*		Avg Ann'l P/E Ratio	*18.5*
--	1.40	1.78	1.47	1.40	1.14	1.27	1.34	1.32	1.14	*Value Line*		Relative P/E Ratio	*1.15*
--	1.9%	3.5%	2.4%	2.3%	2.8%	2.3%	1.9%	2.0%	1.8%	*estimates*		Avg Ann'l Div'd Yield	*1.8%*
126.4	205.3	223.6	426.2	617.9	621.0	696.8	757.4	830.5	941.3	*1070*	*1185*	Revenues ($mill)	*1650*
2.6	34.7	33.2	73.3	109.2	130.9	145.7	171.7	187.9	233.5	*270*	*325*	Net Profit ($mill)	*470*
39.0%	35.3%	29.2%	33.3%	38.1%	37.2%	36.1%	35.6%	36.6%	33.7%	*38.0%*	*38.0%*	Income Tax Rate	*38.0%*
80.2%	10.1%	15.0%	14.7%	13.8%	13.1%	11.9%	12.5%	16.0%	16.3%	*13.0%*	*11.0%*	AFUDC % to Net Profit	*8.0%*
71.1%	66.3%	70.3%	72.4%	70.8%	70.6%	69.1%	67.8%	63.8%	67.9%	*69.0%*	*67.5%*	Long-Term Debt Ratio	*61.0%*
28.9%	33.7%	29.7%	27.6%	29.2%	29.4%	30.9%	32.2%	36.2%	32.1%	*31.0%*	*32.5%*	Common Equity Ratio	*39.0%*
680.0	780.6	1794.5	2041.5	3177.3	3445.9	3614.3	3903.9	3910.2	5025.8	*5300*	*5470*	Total Capital ($mill)	*6825*
513.7	603.6	1197.9	1960.4	2304.4	2542.1	2872.3	3415.8	4134.6	4846.5	*5550*	*6185*	Net Plant ($mill)	*8625*
2.3%	6.2%	3.0%	5.7%	5.4%	5.7%	6.1%	6.3%	6.7%	6.2%	*6.5%*	*7.5%*	Return on Total Cap'l	*8.5%*
1.3%	13.2%	6.2%	13.0%	11.8%	12.9%	13.0%	13.6%	13.3%	14.5%	*16.5%*	*18.5%*	Return on Shr. Equity	*17.5%*
1.3%	13.2%	6.2%	13.0%	11.8%	12.9%	13.0%	13.6%	13.3%	14.5%	*16.5%*	*18.5%*	Return on Com Equity E	*17.5%*
1.3%	6.5%	NMF	4.5%	5.4%	6.8%	7.1%	8.0%	8.0%	9.3%	*11.0%*	*12.5%*	Retained to Com Eq	*12.0%*
--	50%	115%	66%	54%	48%	45%	41%	40%	36%	*35%*	*33%*	All Div'ds to Net Prof	*33%*

CAPITAL STRUCTURE as of 6/30/14
Total Debt $4005.5 mill. **Due in 5 Yrs** $1616.2 mill.
LT Debt $3755.5 mill. **LT Interest** $174.1 mill.
(LT interest earned: 3.1x)
Pension Assets-12/13 $48.9 mill. **Oblig.** $73.5 mill.

Pfd Stock None

Common Stock 155,585,300 shs. as of 8/1/14

MARKET CAP: $6.1 billion (Large Cap)

CURRENT POSITION ($MILL.)	2012	2013	6/30/14
Cash Assets	26.2	34.3	9.0
Receivables	72.2	89.3	123.5
Inventory (FIFO)	37.4	32.0	29.4
Other	62.4	35.9	45.5
Current Assets	198.2	191.5	207.4
Accts Payable	102.5	111.1	126.9
Debt Due	651.9	200.0	250.0
Other	228.4	188.3	184.0
Current Liab.	982.8	499.4	560.9
Fix Chg. Cov.	265%	281%	304%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	--	12.0%	*11.5%*
"Cash Flow"	--	14.0%	*15.0%*
Earnings	--	19.0%	*15.5%*
Dividends	--	5.5%	*12.5%*
Book Value	--	13.0%	*11.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	179.4	185.1	191.3	201.6	757.4
2012	196.7	197.4	214.8	221.6	830.5
2013	217.3	229.8	238.8	255.4	941.3
2014	258.6	263.2	270.1	*278.1*	*1070*
2015	*285*	*290*	*300*	*310*	*1185*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.27	.28	.28	.27	1.10
2012	.29	.27	.33	.31	1.20
2013	.32	.30	.37	.48	1.47
2014	.43	.34	.47	*.51*	*1.75*
2015	*.50*	*.52*	*.54*	*.54*	*2.10*

Calendar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.107	.107	.112	.112	.44
2011	.112	.112	.118	.118	.46
2012	.117	.117	.126	.126	.49
2013	.126	.126	.1425	.1425	.54
2014	.1425	.1425	.1625	.1625	

BUSINESS: ITC Holdings Corp. engages in the transmission of electricity in the United States. The company operates primarily as a conduit, moving power from generators to local distribution systems either through its own system or in conjunction with neighboring transmission systems. Acquired Michigan Electric Transmission Company 10/06; Interstate Power & Light's transmission assets 12/07. Has assets in Michigan, Iowa, Minnesota, Illinois, Missouri, and Kansas. Operations are regulated by the Federal Energy Regulatory Commission (FERC). '13 reported depreciation rate: 2.2%. Has about 500 employees. Chairman, President & CEO: Joseph L. Welch. Inc.: Michigan. Address: 27175 Energy Way, Novi, Michigan 48377. Tel.: 248-946-3000. Internet: www.itctransco.com.

ITC Holdings is not like other electric utilities. ITC is the sole publicly traded transmission-only company. It benefits from a forward-looking regulatory mechanism that enables it to recover expected capital spending and increases in most kinds of operating expenses. ITC is regulated by the Federal Energy Regulatory Commission (FERC) and is allowed to earn returns on equity that are well above those allowed by most state regulatory commissions. However . . .

FERC is reviewing the allowed ROEs for transmission in ITC's region. Some groups representing large customers have complained that the allowed ROEs are too generous. Already, transmission owners in New England have seen their allowed ROEs lowered, although they are still comfortably above ROEs granted by state regulatory commissions. Based on ITC's projected rate base at the end of 2014, a cut of one percentage point in the company's allowed ROE would reduce net profit by $26 million. (Note that our estimates and projections do not reflect any such reduction.) This matter might not be resolved until 2016.

We continue to estimate strong earnings growth in 2014 and 2015. This year, the comparisons in the first three quarters were easy because in 2013 ITC incurred expenses associated with an unsuccessful attempt to purchase another company's transmission assets. Our 2014 estimate of $1.75 a share is below management's targeted range of $1.83-$1.90 because our presentation *includes* a $0.12-a-share charge in the second quarter for the early retirement of debt. We have trimmed our 2015 forecast by $0.05 a share, but continue to expect strong growth, based on ITC's capital spending plans. Our estimate is within the company's targeted range of $2.00-$2.15 a share.

ITC is repurchasing stock. The company plans to buy back $250 million by the end of 2015, and has begun an accelerated share repurchase of up to $150 million. Through September 30th, it had bought back 2.9 million shares.

ITC stock is timely, and offers respectable 3- to 5-year total return potential. Unlike most utilities, however, its doesn't stand out for its dividend yield.

Paul E. Debbas, CFA *December 19, 2014*

(A) Diluted earnings. Next earnings report due late February. (B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan available. † Shareholder investment plan available. (C) Includes intangibles. In '13: $1.2 billion, $7.65/sh. (D) In millions, adjusted for stock split. (E) Rates allowed on common equity: 12.16%-13.88%. Earned on avg. com. eq., '13: 15.2%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	100

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MGE ENERGY INC. NDQ-MGEE

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
46.25	20.2 (Trailing: 20.2 / Median: 16.0)	1.09	2.4%

VALUE LINE

TIMELINESS 4 Lowered 12/5/14
SAFETY 1 New 1/3/03
TECHNICAL 4 Lowered 12/19/14
BETA .70 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
High:	23.9	24.3	25.8	24.7	24.8	24.3	25.5	29.1	31.9	37.4	40.5	46.5
Low:	16.7	18.4	20.3	19.5	19.6	18.6	18.2	21.4	24.7	28.7	33.4	35.7

Target Price Range 2017 | 2018 | 2019

2017-19 PROJECTIONS

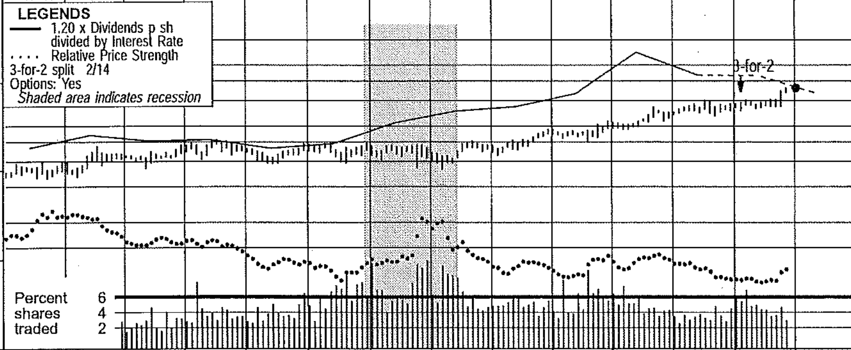
	Price	Gain	Ann'l Total Return
High	55	(+20%)	7%
Low	45	(-5%)	2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	1	0	1	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	66	55	43
to Sell	49	53	62
Hld's(000)	11510	11517	11389



% TOT. RETURN 11/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	21.3	8.0
3 yr.	61.5	72.4
5 yr.	127.1	119.8

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
10.35	11.30	13.00	13.03	13.17	14.59	13.89	16.73	16.13	16.33	17.35	15.40	15.36	15.76	15.61	17.04	*17.85*	*18.55*	Revenues per sh	*21.55*
2.39	2.54	2.59	2.52	2.22	1.96	1.92	2.00	2.34	2.46	2.68	2.66	2.76	2.94	2.98	3.28	*3.45*	*3.70*	"Cash Flow" per sh	*4.85*
.92	.99	1.11	1.08	1.13	1.14	1.18	1.05	1.37	1.51	1.59	1.47	1.67	1.76	1.86	2.16	*2.25*	*2.40*	Earnings per sh A	*3.20*
.86	.87	.88	.89	.89	.90	.91	.92	.93	.94	.96	.97	.99	1.01	1.04	1.07	*1.11*	*1.15*	Div'd Decl'd per sh B ■	*1.30*
1.28	2.11	2.96	1.65	2.97	3.02	3.13	2.80	2.94	4.14	3.08	2.35	1.76	1.88	2.84	3.43	*2.55*	*3.15*	Cap'l Spending per sh	*4.70*
7.56	7.66	8.04	8.45	8.62	9.56	11.06	11.21	11.93	12.99	13.92	14.47	15.14	15.89	16.71	17.81	*18.85*	*20.00*	Book Value per sh E	*23.60*
24.12	24.24	24.93	25.61	26.36	27.52	30.59	30.68	31.46	32.93	34.36	34.67	34.67	34.67	34.67	34.67	*35.00*	*35.00*	Common Shs Outst'g C	*36.00*
16.2	14.0	11.7	14.8	16.0	17.5	18.0	22.4	15.9	15.0	14.2	15.1	15.0	15.8	17.2	17.0	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.84	.80	.76	.76	.87	1.00	.95	1.19	.86	.80	.85	1.01	.95	.99	1.09	.96	*Value Line*		Relative P/E Ratio	*.95*
5.8%	6.3%	6.7%	5.5%	5.0%	4.5%	4.3%	3.9%	4.3%	4.1%	4.2%	4.4%	4.0%	3.6%	3.2%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*2.7%*

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
424.9	513.4	507.5	537.6	596.0	533.8	532.6	546.4	541.3	590.9	*625*	*650*	Revenues ($mill)	*775*
33.8	32.1	42.4	48.8	52.8	51.0	57.7	60.9	64.4	74.9	*80.0*	*85.0*	Net Profit ($mill)	*115*
37.9%	38.2%	37.9%	36.3%	35.5%	35.6%	36.9%	37.1%	37.7%	37.5%	*36.0%*	*35.0%*	Income Tax Rate	*35.0%*
--	--	--	--	--	--	--	--	2.2%	2.0%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
37.4%	39.3%	38.7%	35.2%	36.3%	39.0%	38.9%	39.6%	38.2%	39.3%	*39.0%*	*38.5%*	Long-Term Debt Ratio	*36.5%*
62.6%	60.7%	61.3%	64.8%	63.7%	61.0%	61.1%	60.4%	61.8%	60.7%	*61.0%*	*61.5%*	Common Equity Ratio	*63.5%*
540.5	566.2	612.6	660.1	750.6	822.7	859.4	911.9	937.9	1016.9	*1080*	*1140*	Total Capital ($mill)	*1335*
607.4	667.7	728.4	844.0	901.2	939.8	968.0	995.6	1073.5	1160.2	*1215*	*1275*	Net Plant ($mill)	*1600*
7.1%	6.6%	7.8%	8.1%	7.7%	6.9%	7.6%	7.8%	7.9%	8.3%	*8.5%*	*8.5%*	Return on Total Cap'l	*9.5%*
10.0%	9.3%	11.3%	11.4%	11.0%	10.2%	11.0%	11.1%	11.1%	12.1%	*12.0%*	*12.0%*	Return on Shr. Equity	*13.5%*
10.0%	9.3%	11.3%	11.4%	11.0%	10.2%	11.0%	11.1%	11.1%	12.1%	*12.0%*	*12.0%*	Return on Com Equity D	*13.5%*
2.3%	1.2%	3.7%	4.3%	4.4%	3.4%	4.4%	4.7%	4.9%	6.1%	*6.0%*	*6.5%*	Retained to Com Eq	*8.0%*
77%	87%	67%	62%	60%	66%	60%	57%	56%	50%	*49%*	*47%*	All Div'ds to Net Prof	*41%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $400.5 mill. **Due in 5 Yrs** $71.5 mill.
LT Debt $396.3 mill. **LT Interest** $19.0 mill.
(LT interest earned: 7.5x)

Leases, Uncapitalized Annual rentals $1.7 mill.
Pension Assets-12/13 $277.4 mill.
Obligation $284.0 mill.

Pfd Stock None

Common Stock 34,668,370 shs.
as of 10/31/14
MARKET CAP: $1.6 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+0.8	-0.3	-0.8
Avg. Indust. Use (MWH)	2632	2472	2502
Avg. Indust. Revs. per KWH (¢)	7.38	7.86	7.94
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	770	766	783
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	535	579	676

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	1.5%	-.5%	*5.0%*
"Cash Flow"	3.0%	4.0%	*8.0%*
Earnings	5.5%	5.5%	*9.0%*
Dividends	1.5%	2.0%	*4.0%*
Book Value	6.5%	5.5%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	164.6	117.3	133.6	130.9	546.4
2012	149.3	117.2	137.8	137.0	541.3
2013	167.2	128.3	140.1	155.3	590.9
2014	210.2	128.8	135.1	*150.9*	*625*
2015	*215*	*135*	*145*	*155*	*650*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.51	.37	.61	.27	1.76
2012	.46	.41	.68	.31	1.86
2013	.65	.40	.70	.41	2.16
2014	.80	.41	.67	*.37*	*2.25*
2015	*.80*	*.45*	*.72*	*.43*	*2.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.2456	.2456	.2501	.2501	.99
2011	.2501	.2501	.2551	.2551	1.01
2012	.2551	.2551	.2634	.2634	1.04
2013	.2634	.2634	.2717	.2717	1.07
2014	.2717	.2717	.2825	.2825	

BUSINESS: MGE Energy Inc. is a holding company for Madison Gas and Electric, which provides electric service to approximately 141,000 customers in a 316-square-mile area of Dane County and gas service to 147,000 customers in 1,639 square miles in seven counties in Wisconsin. Electric revenue breakdown, '13: residential, 33%; commercial, 52%; industrial, 5%; public authorities and other, 10%. Generating sources, '13: coal, 54%; purchased power, 37%; natural gas and other, 9%. Fuel costs: 21% of revenues. '13 reported depreciation rate: 3.3%. Has 695 employees. Chairman, President & CEO: Gary J. Wolter. Incorporated: Wisconsin. Address: 133 South Blair St., Madison, WI 53788. Telephone: 608-252-7000. Internet: www.mgeenergy.com.

Shares of MGE Energy have traded higher in recent months. This occurred despite lackluster results in the recent interim. Revenues and share earnings declined modestly for the third quarter, due to cooler-than-normal temperatures. A moderate decrease in electric utility revenues was partly offset by solid growth in gas utility revenues. Operating costs declined somewhat, as well, but so did other income. We look for unimpressive performance for the December quarter, as well. Still, revenues and share earnings will probably advance at a nice pace for full-year 2014, given the strong performance achieved in the first quarter.

We expect a rate case decision shortly. Madison Gas and Electric originally filed an application with the Public Service Commission of Wisconsin in April, requesting a 2.8% increase to electric rates and a 2.3% decrease to gas rates. The company cited costs associated with the construction of emission-reduction equipment and improvements to the state's electric transmission system as reasons for the proposed electric rate increase. Since then, updates have been made to reflect greater fuel and purchased power costs, lower transmission expense, and higher pension and post-retirement costs. Including the revisions would adjust the electric rate increase requested to 4.3%, and the gas rate decrease sought to 1.4%.

We expect a measure of improvement in 2015. The company's utility operations will probably further gain from favorable demographics. A healthy local economy ought to drive population growth and demand for power in and around Madison, Wisconsin. Efforts to control operating expenses should support the bottom line.

Conservative accounts may find something to like here. The company has established a track record of stable operating results. Low exposure to economically sensitive industrial customers affords it greater earnings stability. Also, leverage appears quite manageable. Thus, MGE earns high marks for Safety, Financial Strength, Price Stability, and Earnings Predictability. But the dividend yield does not stand out for a utility, and total return potential is nothing to write home about. Moreover, the stock is untimely.

Michael Napoli, CFA *December 19, 2014*

(A) Diluted earnings. Next earnings report due late February/early March. (B) Dividends historically paid in mid-March, June, September, and December. ■ Dvd. reinvestment plan available. (C) In millions, adjusted for split.. (D) Rate allowed on common equity in '13: 10.3%; earned on common equity, '13: 12.1%. Regulatory Climate: Above Average. (E) Includes regulatory assets. In 2013: $113.5 mill., $3.27 per share.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	95

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NEXTERA ENERGY NYSE-NEE

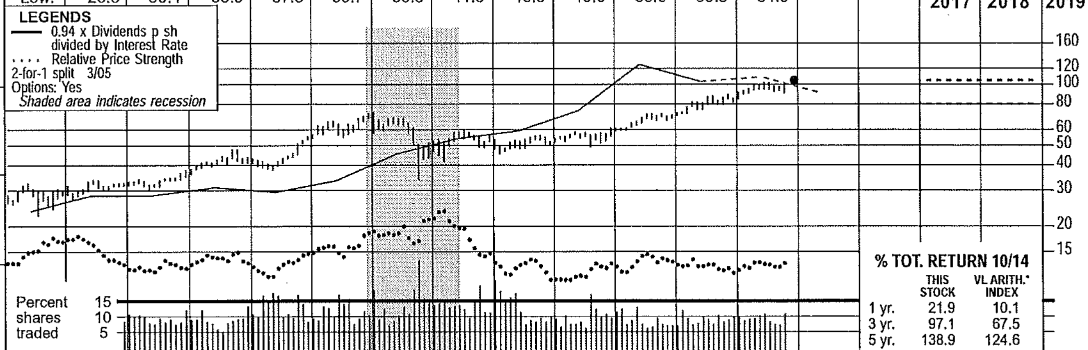
RECENT PRICE 104.80 | P/E RATIO 20.2 (Trailing: 24.1 / Median: 14.0) | RELATIVE P/E RATIO 1.11 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 3 Raised 4/25/14
SAFETY 2 Lowered 2/26/10
TECHNICAL 4 Lowered 11/14/14
BETA .70 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
High:	34.0	38.1	48.1	55.6	72.8	73.8	60.6	56.3	61.2	72.2	89.8	105.9
Low:	26.8	30.1	35.9	37.8	53.7	33.8	41.5	45.3	49.0	58.6	69.8	84.0

Target Price Range 2017 | 2018 | 2019

LEGENDS
— 0.94 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 3/05
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(Nil)	3%
Low	80	(-25%)	-3%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	1	0	0	0	1	1
to Sell	2	0	1	2	0	0	1	1	1

Institutional Decisions

	4Q2013	1Q2014	2Q2014
to Buy	397	400	404
to Sell	429	446	446
Hld's(000)	316004	318167	319782

Percent shares traded 15 / 10 / 5

% TOT. RETURN 10/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	21.9	10.1
3 yr.	97.1	67.5
5 yr.	138.9	124.6

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
18.43	18.03	20.15	24.10	22.74	26.13	28.27	30.00	38.75	37.47	40.13	37.82	36.39	36.88	33.62	34.80	*36.35*	*35.80*	Revenues per sh	*38.25*
5.39	4.86	4.94	5.02	4.51	5.36	5.60	6.18	6.77	6.85	8.03	8.75	9.62	9.29	8.69	10.54	*10.55*	*11.50*	"Cash Flow" per sh	*13.75*
1.93	2.04	2.07	2.31	2.01	2.45	2.46	2.32	3.23	3.27	4.07	3.97	4.74	4.82	4.56	4.83	*4.60*	*5.50*	Earnings per sh A	*6.75*
1.00	1.04	1.08	1.12	1.16	1.20	1.30	1.42	1.50	1.64	1.78	1.89	2.00	2.20	2.40	2.64	*2.90*	*3.08*	Div'd Decl'd per sh B ■ †	*3.80*
1.71	2.41	3.70	3.28	3.44	3.75	3.75	4.09	9.22	12.32	12.80	14.52	13.89	15.93	22.31	15.36	*12.75*	*9.30*	Cap'l Spending per sh	*10.00*
14.18	15.04	15.91	17.10	17.48	18.91	20.25	21.52	24.49	26.35	28.57	31.35	34.36	35.92	37.90	41.47	*44.70*	*48.35*	Book Value per sh C	*57.50*
361.42	357.11	351.53	351.71	365.51	368.53	372.24	394.85	405.40	407.35	408.92	413.62	420.86	416.00	424.00	435.00	*443.00*	*458.00*	Common Shs Outst'g D	*470.00*
16.2	13.0	12.8	12.5	14.2	12.6	13.6	17.9	13.7	18.9	14.5	13.4	10.8	11.5	14.4	16.6	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
.84	.74	.83	.64	.78	.72	.72	.95	.74	1.00	.87	.89	.69	.72	.92	.93	*Value Line*		Relative P/E Ratio	*.85*
3.2%	3.9%	4.1%	3.9%	4.1%	3.9%	3.9%	3.4%	3.4%	2.7%	3.0%	3.5%	3.9%	4.0%	3.6%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*4.1%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $29423 mill. Due in 5 Yrs $12584 mill.
LT Debt $24853 mill. LT Interest $1076 mill.
(LT interest earned: 3.0x)

Pension Assets-12/13 $3692 mill. Oblig. $2254 mill.
Pfd Stock None

Common Stock 436,482,306 shs.

MARKET CAP: $46 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
10522	11846	15710	15263	16410	15643	15317	15341	14256	15136	*16100*	*16400*	Revenues ($mill)	*18000*
887.0	901.0	1281.0	1312.0	1639.0	1615.0	1957.0	2021.0	1911.0	2062.0	*2025*	*2495*	Net Profit ($mill)	*3230*
23.1%	23.8%	23.7%	21.9%	21.5%	16.8%	21.4%	22.4%	26.6%	26.9%	*31.5%*	*30.0%*	Income Tax Rate	*30.0%*
4.2%	5.4%	3.8%	5.7%	6.6%	7.9%	4.4%	4.4%	10.8%	7.0%	*6.0%*	*7.0%*	AFUDC % to Net Profit	*7.0%*
51.6%	48.6%	49.1%	51.2%	54.2%	55.7%	55.5%	58.2%	59.1%	57.1%	*56.0%*	*53.0%*	Long-Term Debt Ratio	*48.5%*
48.4%	51.4%	50.9%	48.8%	45.8%	44.3%	44.5%	41.8%	40.9%	42.9%	*44.0%*	*47.0%*	Common Equity Ratio	*51.5%*
15564	16538	19521	22015	25514	29267	32474	35753	39245	42009	*44775*	*47175*	Total Capital ($mill)	*52500*
21226	22463	24499	28652	32411	36078	39075	42490	49413	52720	*55725*	*57200*	Net Plant ($mill)	*62100*
7.0%	6.9%	8.0%	7.5%	7.9%	6.9%	7.4%	7.0%	6.2%	6.2%	*5.5%*	*6.5%*	Return on Total Cap'l	*7.5%*
11.8%	10.6%	12.9%	12.2%	14.0%	12.5%	13.5%	13.5%	11.9%	11.4%	*10.0%*	*11.5%*	Return on Shr. Equity	*12.0%*
11.8%	10.6%	12.9%	12.2%	14.0%	12.5%	13.5%	13.5%	11.9%	11.4%	*10.0%*	*11.5%*	Return on Com Equity E	*12.0%*
5.6%	4.2%	6.9%	6.1%	7.9%	6.5%	7.8%	7.4%	5.6%	5.2%	*4.0%*	*5.0%*	Retained to Com Eq	*5.5%*
53%	60%	46%	50%	44%	47%	42%	46%	53%	54%	*63%*	*56%*	All Div'ds to Net Prof	*55%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-1.4	-1.4	+.9
Avg. Indust. Use (MWH)	343	336	296
Avg. Indust. Revs. per KWH (¢)	7.40	6.87	6.51
Capacity at Peak (Mw)	26538	26020	26236
Peak Load, Summer (Mw)	21619	21440	21576
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.7	+1.8
Fixed Charge Cov. (%)	311	278	295

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	3.5%	-2.0%	1.5%
"Cash Flow"	6.5%	5.5%	6.5%
Earnings	7.5%	6.0%	6.0%
Dividends	7.5%	8.0%	8.0%
Book Value	8.0%	7.5%	7.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	3134	3961	4382	3864	15341
2012	3371	3667	3843	3375	14256
2013	3279	3833	4394	3630	15136
2014	3674	4029	4654	*3743*	*16100*
2015	*3650*	*4150*	*4750*	*3850*	*16400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.64	1.38	1.20	1.59	4.82
2012	1.11	1.45	.98	1.02	4.56
2013	1.00	1.44	1.64	.75	4.83
2014	.98	1.12	1.50	*1.00*	*4.60*
2015	*1.25*	*1.45*	*1.65*	*1.15*	*5.50*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.50	.50	.50	.50	2.00
2011	.55	.55	.55	.55	2.20
2012	.60	.60	.60	.60	2.40
2013	.66	.66	.66	.66	2.64
2014	.725	.725	.725		

BUSINESS: NextEra Energy, Inc. (formerly FPL Group, Inc.) is a holding company for Florida Power & Light Company (FPL), which provides electricity to 4.7 million customers in a 27,650-sq.-mi. area in eastern & southern Florida. NextEra Energy Resources is a non-regulated power generator with nuclear, gas, & wind ownership. Revenue breakdown: residential, 54%; commercial, 37%; industrial & other, 8%. Generating sources: gas, 67%; nuclear, 23%; coal, 5%; purchased, 5%. Fuel costs: 33% of revenues. '13 reported deprec. rate (utility): 3.4%. Has 13,900 employees. Chairman: Lewis Hay, III. President and CEO: James L. Robo. Inc.: Florida. Address: 700 Universe Boulevard, Juno Beach, Florida 33408. Tel.: 561-694-4000. Internet: www.nexteraenergy.com.

The earnings decline we estimate for NextEra Energy in 2014 belies the company's solid performance this year. We *include* mark-to-market accounting credits or charges in our earnings presentation because they are an ongoing part of the company's operations. These reduced profits by $0.64 a share in the first nine months of 2014, compared with a $0.04 credit in the same period of 2013. (Over time, these items even out.) Florida Power & Light is benefiting from capital investments that are being recovered in rates and the economic rebound in the utility's service area. NextEra Energy Resources is benefiting from additions to its portfolio of contracted renewable assets. We think a continuation of these trends will boost earnings in 2015. Our estimate is within NextEra's guidance of $5.40-$5.70 a share. We don't assume any mark-to-market gains or losses in our estimates because these are impossible to predict.

The initial public offering of NextEra Energy Partners has gone well. The master limited partnership for some contracted renewable assets has risen more than 40% from the IPO price. However, NextEra incurred $0.15 a share of spinoff costs in the second quarter.

FPL has a major capital project under way, and other investments are planned. A plant modernization project is on track for completion in mid-2016 at a cost of $1 billion. (Two other plant upgrades in recent years were completed ahead of schedule and below budget.) FPL is a one-third partner in a $3 billion pipeline to transport natural gas to Florida. Federal regulatory approval is needed. The pipeline is expected to be in service by mid-2017. And the utility is asking the Florida regulators for permission to invest in natural gas reserves in order to reduce gas-price volatility to its customers. A ruling is expected by early 2015.

The market is recognizing NextEra's good prospects. The stock price is up more than 20% so far in 2014. However, even when reflecting a dividend hike we estimate in the first quarter of 2015, the dividend yield is a cut below the utility average. With the recent price near the upper end of our 2017-2019 Target Price Range, total return potential is minuscule.

Paul E. Debbas, CFA *November 21, 2014*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '00, (5¢); '02, (60¢); '03, 5¢; '11, (24¢); '13, (80¢); gain on disc. ops.: '13, 44¢. '11 EPS don't add due to rounding. Next earnings report due late Jan. (B) Div'ds historically paid in mid-Mar., mid-June, mid-Sept., & mid-Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '13: $5.18/sh. (D) In millions, adj. for stock split. (E) Rate allowed on com. eq. in '13: 9.5%-11.5%; earned on avg. com. eq., '13: 12.1%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	80

NORTHEAST UTILITIES NYSE-NU

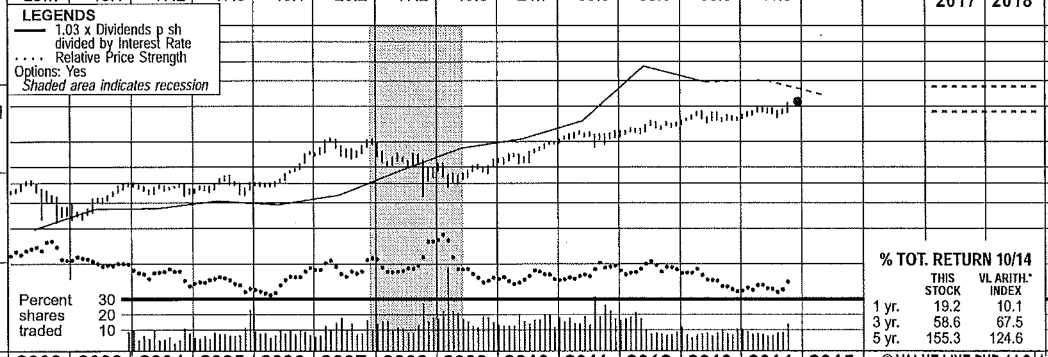
RECENT PRICE 50.54 | P/E RATIO 18.0 (Trailing: 20.7 Median: 18.0) | RELATIVE P/E RATIO 0.99 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 2 Raised 11/21/14
SAFETY 2 Raised 5/25/12
TECHNICAL 4 Lowered 11/14/14
BETA .75 (1.00 = Market)

High:	20.3	20.3	22.0	28.9	33.6	31.6	26.5	32.2	36.5	40.9	45.7	50.9
Low:	13.1	17.2	17.3	19.1	26.2	17.2	19.0	24.7	30.0	33.5	38.6	41.3

Target Price Range 2017 | 2018 | 2019

LEGENDS
— 1.03 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+20%)	7%
Low	45	(-10%)	1%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	2	0	0	0	0	1	0	1
to Sell	1	2	1	2	0	0	1	0	4

Institutional Decisions

	4Q2013	1Q2014	2Q2014
to Buy	185	221	228
to Sell	221	192	187
Hld's(000)	210814	209428	211525

% TOT. RETURN 10/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	19.2	10.1
3 yr.	58.6	67.5
5 yr.	155.3	124.6

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
28.77	33.91	40.86	52.82	40.89	47.53	51.82	41.85	44.64	37.27	37.22	30.97	27.76	25.21	19.98	23.16	*24.35*	*24.90*	Revenues per sh	*27.00*
3.73	5.68	3.39	10.48	6.32	5.80	5.00	5.46	3.69	4.82	6.16	4.96	5.68	4.88	4.03	5.22	*4.75*	*5.20*	"Cash Flow" per sh	*6.50*
d.36	d1.14	d.20	1.37	1.08	1.24	.91	.98	.82	1.59	1.86	1.91	2.10	2.22	1.89	2.49	*2.55*	*2.85*	Earnings per sh A	*3.50*
--	.10	.40	.45	.53	.58	.63	.68	.73	.78	.83	.95	1.03	1.10	1.32	1.47	*1.57*	*1.68*	Div'd Decl'd per sh B ■	*2.00*
1.79	2.50	2.88	3.40	3.86	4.31	4.85	5.89	5.49	7.14	8.06	5.17	5.41	6.08	4.69	4.62	*5.30*	*5.95*	Cap'l Spending per sh	*6.25*
15.63	15.80	15.43	16.27	17.33	17.73	17.80	18.46	18.14	18.65	19.38	20.37	21.60	22.65	29.41	30.49	*31.35*	*32.50*	Book Value per sh C	*36.25*
130.95	131.87	143.82	130.13	127.56	127.70	129.03	131.59	154.23	156.22	155.83	175.62	176.45	177.16	314.05	315.27	*316.50*	*317.50*	Common Shs Outst'g D	*325.00*
--	--	--	14.1	16.1	13.4	20.8	19.8	27.1	18.7	13.7	12.0	13.4	15.4	19.9	16.9	Bold figures are		Avg Ann'l P/E Ratio	*14.5*
--	--	--	.72	.88	.76	1.10	1.05	1.46	.99	.82	.80	.85	.97	1.27	.95	Value Line		Relative P/E Ratio	*.90*
--	.6%	1.9%	2.3%	3.0%	3.5%	3.3%	3.5%	3.3%	2.6%	3.2%	4.2%	3.6%	3.2%	3.5%	3.5%	estimates		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 6/30/14
Total Debt $9447.7 mill. Due in 5 Yrs $3410.1 mill.
LT Debt $8147.1 mill. LT Interest $360.9 mill.
(LT interest earned: 4.4x)

Leases, Uncapitalized Annual rentals $20.1 mill.
Pension Assets-12/13 $3985.9 mill.
Oblig. $4676.5 mill.
Pfd Stock $155.6 mill. Pfd Div'd $7.6 mill.
Incl. 2,324,000 shs $1.90-$3.28 rates ($50 par) not subject to mandatory redemption.
Common Stock 316,385,790 shs.
as of 7/31/14
MARKET CAP: $16 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
6686.7	5507.3	6884.4	5822.2	5800.1	5439.4	4898.2	4465.7	6273.8	7301.2	*7700*	*7900*	Revenues ($mill)	*8650*
122.1	128.5	126.2	251.5	296.2	335.6	377.8	400.3	533.0	793.7	*810*	*910*	Net Profit ($mill)	*1120*
29.8%	30.8%	--	30.3%	29.7%	34.9%	36.6%	29.9%	34.0%	35.0%	*36.0%*	*35.0%*	Income Tax Rate	*35.0%*
6.8%	17.4%	21.5%	13.9%	15.8%	4.6%	7.1%	8.6%	2.3%	1.4%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
64.2%	63.2%	58.7%	59.2%	60.4%	57.2%	55.1%	53.4%	43.7%	44.3%	*45.0%*	*45.5%*	Long-Term Debt Ratio	*45.5%*
34.0%	35.1%	39.7%	39.2%	38.1%	41.5%	43.6%	45.3%	55.4%	54.8%	*54.5%*	*54.0%*	Common Equity Ratio	*53.5%*
6749.4	6923.2	7052.0	7431.1	7926.2	8629.5	8741.8	8856.0	16675	17544	*18250*	*19125*	Total Capital ($mill)	*21700*
5864.2	6417.2	6242.2	7229.9	8207.9	8840.0	9567.7	10403	16605	17576	*18700*	*19975*	Net Plant ($mill)	*23900*
2.8%	3.5%	2.9%	5.0%	5.4%	5.4%	5.8%	5.9%	4.2%	5.5%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
5.1%	5.0%	4.3%	8.3%	9.4%	9.1%	9.6%	9.7%	5.7%	8.1%	*8.0%*	*8.5%*	Return on Shr. Equity	*9.5%*
5.1%	5.1%	4.3%	8.4%	9.6%	9.2%	9.8%	9.8%	5.7%	8.2%	*8.0%*	*9.0%*	Return on Com Equity E	*9.5%*
1.6%	1.5%	.3%	4.3%	5.3%	4.7%	5.0%	5.0%	1.6%	3.4%	*3.0%*	*3.5%*	Retained to Com Eq	*4.0%*
70%	72%	94%	50%	45%	50%	49%	50%	72%	59%	*62%*	*59%*	All Div'ds to Net Prof	*58%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-1.2	+47.0	+1.0
Avg. Indust. Use (MWH)	624	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.4	+59.8	NA
Fixed Charge Cov. (%)	291	320	427

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-7.0%	-10.5%	3.0%
"Cash Flow"	-4.5%	-.5%	5.5%
Earnings	6.0%	9.0%	8.0%
Dividends	9.5%	11.0%	7.5%
Book Value	5.0%	8.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	1235	1048	1115	1068	4465.7
2012	1100	1629	1861	1684	6273.8
2013	1995	1636	1893	1777	7301.2
2014	2291	1678	1893	*1838*	*7700*
2015	*2250*	*1750*	*2000*	*1900*	*7900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.64	.44	.51	.64	2.22
2012	.56	.15	.66	.55	1.89
2013	.72	.54	.66	.56	2.49
2014	.74	.40	.74	*.67*	*2.55*
2015	*.80*	*.60*	*.80*	*.65*	*2.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.25625	.25625	.25625	.25625	1.02
2011	.275	.275	.275	.275	1.10
2012	.294	.343	.343	.343	1.32
2013	.3675	.3675	.3675	.3675	1.47
2014	.3925	.3925	.3925		

BUSINESS: Northeast Utilities is the parent of utilities that have 3.1 mill. elec., 492,000 gas customers. Connecticut Light & Power (CL&P) serves most of CT; Public Service Co. of New Hampshire (PSNH) supplies power to three fourths of NH's population; Western Massachusetts Electric Co. (WMECO) serves western MA; NSTAR supplies power to parts of eastern MA & gas to central & eastern MA. Acq'd NSTAR 4/12. Elec. rev. breakdown: res'l, 49%; comm'l, 38%; ind'l, 5%; other, 8%. Generating sources not avail. Fuel costs: 34% of revs. '13 reported depr. rates: 2.5%-3.0%. Has 8,700 empls. Chairman, President & CEO: Thomas J. May. Inc.: MA. Address: One Federal St., Building 111-4, Springfield, MA 01105. Tel.: 413-785-5871. Internet: www.nu.com.

Northeast Utilities' Connecticut Light & Power subsidiary is awaiting an order on its rate case. CL&P requested a $221.1 million (5.7%) rate increase, based on a 10.2% return on a 50.38% common-equity ratio. The utility wants to recover capital investments it has made to enhance system reliability, along with $300 million of storm-related costs that were deferred. CL&P also proposed a regulatory mechanism that will decouple electric revenues and volume. New tariffs will take effect at the start of December.

Two gas rate cases are upcoming. Next month, NSTAR Gas will ask the Massachusetts commission for a rate hike. The utility is not earning an adequate ROE. Yankee Gas will file an application in Connecticut in the second quarter of 2015. New rates won't take effect until 2016.

Electric transmission is an important part of NU's business. The company's four-year capital budget calls for spending $3.7 billion through 2017. However, the Federal Energy Regulatory Commission (FERC) reduced the allowed ROE for transmission providers in New England, and this will hurt NU's earning power by $0.05-$0.06 a share annually. Even so, the company should continue to earn a higher ROE on transmission than on distribution.

The company has good earnings growth potential. NU should benefit from rate relief, cuts in operating expenses stemming from its merger with NSTAR in 2012, increased transmission investment, and customer conversions to gas heat from oil and other fuels. We think management's profit growth goal of 6%-8% annually is attainable. In fact, we expect NU to exceed this target in 2015 because the company took a $0.10-a-share charge in the second period of 2014 to reflect the aforementioned FERC ruling.

NU is an equal partner in a proposed gas pipeline joint venture with Spectra Energy. Each company's share of the project would be $1.5 billion. The pipeline is expected to be in service in November of 2018.

The profit and dividend growth that we project through 2017-2019 is reflected in the share price. Neither the dividend yield nor the long-term total return potential stands out among utilities.

Paul E. Debbas, CFA *November 21, 2014*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, 10¢; '03, (32¢); '04, (7¢); '05, ($1.36); '08, (19¢); '10, 9¢. '11 & '13 EPS don't add due to rounding, '12 due to change in shs. Next earnings report due mid-Feb. (B) Div'ds historically paid late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. def'd chgs. In '13: $23.09/sh. (D) In mill. (E) Rate allowed on com. eq. in MA: '11, 9.6%; in CT: (elec.) '10, 9.4% (gas) '11, 8.83%; in NH: '10, 9.67%; earn. on avg. com. eq., '13: 8.3%. Regul. Clim.: CT, Below Avg.; NH, Avg.; MA, Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	85

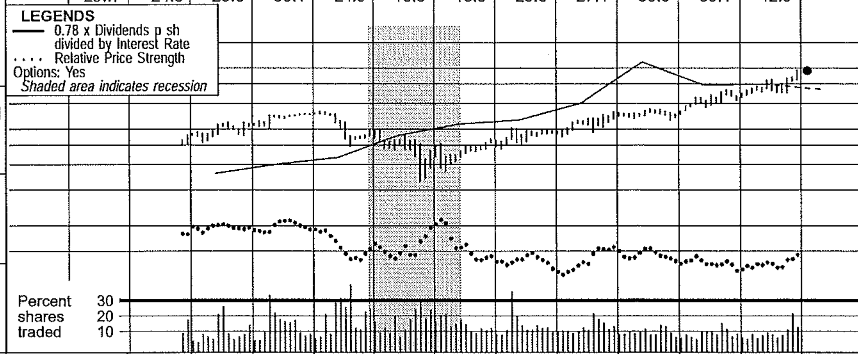
NORTHWESTERN NYSE-NWE

RECENT PRICE	58.02	P/E RATIO	18.0 (Trailing: 20.6; Median: NMF)	RELATIVE P/E RATIO	0.98	DIV'D YLD	3.3%	VALUE LINE

TIMELINESS 2 Raised 9/19/14
SAFETY 3 New 5/4/12
TECHNICAL 3 Raised 12/5/14
BETA .70 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
High:	28.2	32.5	35.8	36.7	29.7	26.8	30.6	36.6	38.0	47.2	58.7
Low:	24.8	25.5	30.1	24.5	16.5	18.5	23.8	27.4	33.0	35.1	42.6

Target Price Range
2017 | 2018 | 2019



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+5%)	4%
Low	40	(-30%)	-4%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	87	88	79
to Sell	92	84	93
Hld's(000)	37582	38301	38766

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	35.0	6.9
3 yr.	76.8	73.7
5 yr.	167.4	107.3

NorthWestern Corporation filed for protection under Chapter 11 of the Federal Bankruptcy Code on September 14, 2003. On November 1, 2004, the company emerged from a bankruptcy reorganization. All old common shares were canceled and 35,500,000 new shares (along with 4,620,333 warrants) were issued. The stock initially traded on NASDAQ under the symbol NWEC and moved to the NYSE under the symbol NWE in May of 2008.

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
29.18	32.57	31.49	30.79	35.09	31.72	30.66	30.80	28.76	29.80	25.55	29.25	Revenues per sh	32.25
3.20	4.00	3.62	3.70	4.40	4.62	4.76	5.42	5.18	5.45	5.20	6.45	"Cash Flow" per sh	7.25
d14.32	1.71	1.31	1.44	1.77	2.02	2.14	2.53	2.26	2.46	2.95	3.20	Earnings per sh A	3.50
--	1.00	1.24	1.28	1.32	1.34	1.36	1.44	1.48	1.52	1.60	1.92	Div'd Decl'd per sh B ■ †	2.15
2.25	2.26	2.81	3.00	3.47	5.26	6.30	5.20	5.89	5.95	5.80	6.50	Cap'l Spending per sh	5.50
19.92	20.60	20.65	21.12	21.25	21.86	22.64	23.68	25.09	26.60	31.75	33.00	Book Value per sh C	37.00
35.60	35.79	35.97	38.97	35.93	36.00	36.23	36.28	37.22	38.75	47.00	47.00	Common Shs Outst'g D	47.00
--	17.1	26.0	21.7	13.9	11.5	12.9	12.6	15.7	16.9	16.5		Avg Ann'l P/E Ratio	14.5
--	.91	1.40	1.15	.84	.77	.82	.79	1.00	.95	.85		Relative P/E Ratio	.90
--	3.4%	3.6%	4.1%	5.4%	5.7%	4.9%	4.5%	4.2%	3.7%	3.3%		Avg Ann'l Div'd Yield	4.3%
1039.0	1165.8	1132.7	1200.1	1260.8	1141.9	1110.7	1117.3	1070.3	1154.5	1200	1375	Revenues ($mill)	1515
41.1	61.5	49.2	53.2	67.6	73.4	77.4	92.6	83.7	94.0	115	150	Net Profit ($mill)	170
--	38.5%	40.3%	37.8%	37.3%	17.2%	25.0%	9.8%	9.6%	13.2%	NMF	17.0%	Income Tax Rate	20.0%
2.9%	2.1%	3.3%	2.5%	2.3%	7.2%	22.7%	5.4%	15.2%	14.1%	13.0%	10.0%	AFUDC % to Net Profit	6.0%
51.8%	44.3%	49.9%	50.1%	46.8%	56.4%	57.2%	52.2%	53.8%	53.5%	53.0%	50.0%	Long-Term Debt Ratio	45.5%
48.2%	55.7%	50.1%	49.9%	53.2%	43.6%	42.8%	47.8%	46.2%	46.5%	47.0%	50.0%	Common Equity Ratio	54.5%
1472.9	1324.0	1482.2	1648.4	1434.3	1803.9	1916.4	1797.1	2020.7	2215.7	3185	3095	Total Capital ($mill)	3175
1379.1	1409.2	1491.9	1770.9	1839.7	1964.1	2118.0	2213.3	2435.6	2690.1	3705	3855	Net Plant ($mill)	4225
5.7%	7.0%	5.2%	5.0%	7.0%	6.0%	6.0%	7.1%	5.5%	5.5%	5.0%	6.0%	Return on Total Cap'l	6.5%
5.8%	8.3%	6.6%	6.5%	8.9%	9.3%	9.4%	10.8%	9.0%	9.1%	8.0%	9.5%	Return on Shr. Equity	9.5%
5.8%	8.3%	6.6%	6.5%	8.9%	9.3%	9.4%	10.8%	9.0%	9.1%	8.0%	9.5%	Return on Com Equity E	9.5%
5.8%	3.5%	.7%	.7%	2.3%	3.2%	3.5%	4.7%	3.2%	3.5%	3.0%	4.0%	Retained to Com Eq	4.0%
--	58%	90%	89%	74%	66%	63%	56%	65%	61%	59%	60%	All Div'ds to Net Prof	60%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $1382.3 mill. **Due in 5 Yrs** $384.2 mill.
LT Debt $1210.7 mill. **LT Interest** $64.2 mill.
Incl. $28.6 mill. capitalized leases.
(LT interest earned: 2.4x)

Leases, Uncapitalized Annual rentals $1.7 mill.
Pension Assets-12/13 $516.4 mill.
Oblig. $567.9 mill.
Pfd Stock None

Common Stock 39,143,732 shs.
as of 10/17/14
MARKET CAP: $2.3 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+2.3	+.3	+1.3
Avg. Indust. Use (MWH)	39347	38865	39486
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	2014	2108	2056
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.8	+.7
Fixed Charge Cov. (%)	237	210	217

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	--	-1.5%	1.5%
"Cash Flow"	--	6.5%	5.0%
Earnings	--	10.0%	6.5%
Dividends	--	3.0%	6.5%
Book Value	--	3.5%	6.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	338.3	251.8	244.0	283.2	1117.3
2012	309.1	244.6	235.8	280.8	1070.3
2013	313.0	260.2	262.2	319.1	1154.5
2014	369.7	270.3	251.9	308.1	1200
2015	400	310	305	360	1375

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.89	.30	.41	.93	2.53
2012	.88	.31	.30	.78	2.26
2013	1.01	.37	.40	.68	2.46
2014	1.17	.20	.77	.81	2.95
2015	1.20	.45	.55	1.00	3.20

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.36	.36	.36	.36	1.44
2012	.37	.37	.37	.37	1.48
2013	.38	.38	.38	.38	1.52
2014	.40	.40	.40	.40	1.60
2015					

BUSINESS: NorthWestern Corporation (doing business as NorthWestern Energy) supplies electricity & gas in the Upper Midwest and Northwest, serving 407,000 electric customers in Montana and South Dakota and 272,000 gas customers in Montana (83% of gross margin), South Dakota (15%), and Nebraska (2%). Electric revenue breakdown: residential, 41%; commercial, 50%; industrial, 5%; other, 4%. Generating sources are not provided by company. Fuel costs: 42% of revenues. '13 reported depreciation rate: 3.2%. Has 1,600 employees. Chairman: Dr. E. Linn Draper Jr. President & CEO: Robert C. Rowe. Incorporated: Delaware. Address: 3010 West 69th Street, Sioux Falls, South Dakota 57108. Telephone: 605-978-2900. Internet: www.northwesternenergy.com.

NorthWestern has completed the purchase of some hydro assets. The company paid $903 million for 633 megawatts of hydro capacity. NorthWestern wants to increase the proportion of its power that comes from its own generating assets (instead of being purchased). The transaction was completed in mid-November. A rate increase of $117 million took effect at that time in order to place the newly purchased assets in the rate base. NorthWestern issued $400 million of common stock and $450 million of long-term debt to finance the deal.

Thanks to the purchase, earnings will likely rise significantly in 2015. This should occur even though the company booked $0.43 a share of tax benefits in the third quarter of 2014. NorthWestern's preliminary 2015 earnings guidance is $3.07-$3.32 a share.

Shareholders can expect a sizable dividend increase soon. NorthWestern is targeting a 60% payout ratio. We estimate that the board of directors will raise the quarterly payout by $0.08 a share (20%).

The company is seeking an electric rate hike in South Dakota. NorthWestern filed for an increase of $26.5 million (20.2%), based on a 10% return on a 53.6% common-equity ratio. The requested rate boost is large, but the utility hasn't had a base rate hike in 35 years. New tariffs are expected to take effect in mid-2015.

NorthWestern is involved in a dispute with the Federal Energy Regulatory Commission (FERC). The company believes that 80% of the costs associated with one of its gas-fired plants should be allocated to its customers in Montana, with the remainder allocated to its FERC-regulated wholesale customers. FERC says only 4% should be allocated to wholesale users, and ordered NorthWestern to make a refund to customers. The company already took a $0.12-a-share charge in the June quarter of 2012. FERC has agreed to a rehearing, but when this matter will be resolved is not known.

This timely stock's dividend yield (reflecting the estimated increase) is average for a utility. With the recent price near the upper end of our 2017-2019 Target Price Range, total return potential is nonexistent.

Paul E. Debbas, CFA *January 30, 2015*

(A) Diluted EPS. Excl. gain (loss) on disc. ops.: '05, (6¢); '06, 1¢; nonrec. gain: '12, 39¢ net. '12 EPS don't add due to rounding. Next earnings report due mid-Feb. (B) Div'ds historically paid in late Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. def'd charges. In '13: $17.34/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in MT in '14 (elec.): 9.8%; in '13 (gas): 9.8%; in SD in '11: none specified; in NE in '07: 10.4%; earned on avg. com. eq., '13: 9.6%. Regul. Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	95

OGE ENERGY CORP. NYSE-OGE

RECENT PRICE 35.82 | P/E RATIO 18.4 (Trailing: 18.1, Median: 14.0) | RELATIVE P/E RATIO 0.99 | DIV'D YLD 2.9% | VALUE LINE

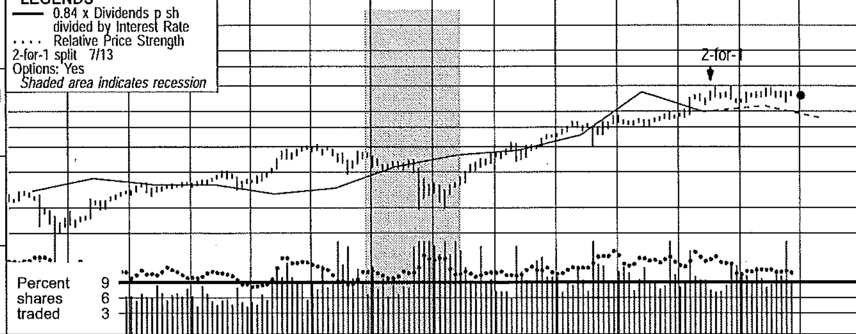
TIMELINESS 3 Raised 5/9/14
SAFETY 1 Raised 9/19/14
TECHNICAL 3 Raised 12/19/14
BETA .90 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
High:	12.2	13.5	15.3	20.3	20.7	18.1	18.9	23.1	28.6	30.1	40.0
Low:	8.0	11.4	12.2	13.2	14.6	9.8	9.9	16.9	20.3	25.1	27.7

High/Low (latest): 39.3 / 32.9

Target Price Range: 2017 | 2018 | 2019

LEGENDS
— 0.84 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/13
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+25%)	9%
Low	35	(Nil)	3%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	2	0	2	0	0	2	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	126	134	147
to Sell	156	141	125
Hld's(000)	115045	116179	117222

% TOT. RETURN 11/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.4	8.0
3 yr.	45.1	72.4
5 yr.	137.7	119.8

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
10.01	13.95	21.17	20.40	19.26	21.62	27.37	32.83	21.96	20.68	21.77	14.79	19.04	19.96	18.58	14.45	*12.25*	*12.70*	Revenues per sh	*14.50*
1.95	2.03	2.07	1.81	1.87	1.82	1.87	1.94	2.23	2.39	2.40	2.69	3.01	3.31	3.69	3.46	*3.30*	*3.50*	"Cash Flow" per sh	*4.00*
1.02	.97	.95	.65	.72	.87	.89	.92	1.23	1.32	1.25	1.33	1.50	1.73	1.79	1.94	*1.95*	*2.10*	Earnings per sh A	*2.50*
.67	.67	.67	.67	.67	.67	.67	.67	.67	.68	.70	.71	.73	.76	.80	.85	*.95*	*1.05*	Div'd Decl'd per sh B ■	*1.40*
.93	1.16	1.15	1.44	1.49	1.04	1.51	1.65	2.67	3.04	4.01	4.37	4.36	6.48	5.85	4.99	*3.05*	*2.65*	Cap'l Spending per sh	*3.75*
6.46	6.55	6.83	6.67	6.27	6.87	7.14	7.59	8.79	9.16	10.14	10.52	11.73	13.06	14.00	15.30	*16.25*	*17.30*	Book Value per sh C	*20.50*
161.60	155.73	155.84	155.98	157.00	174.80	180.00	181.20	182.40	183.60	187.00	194.00	195.20	196.20	197.60	198.50	*200.00*	*201.00*	Common Shs Outst'g D	*204.00*
13.3	12.1	10.6	17.4	14.1	11.8	14.1	14.9	13.7	13.8	12.4	10.8	13.3	14.4	15.2	17.7	*Bold figures are*		Avg Ann'l P/E Ratio	*16.5*
.69	.69	.69	.89	.77	.67	.74	.79	.74	.73	.75	.72	.85	.90	.97	1.00	*Value Line*		Relative P/E Ratio	*1.05*
4.9%	5.7%	6.6%	5.9%	6.6%	6.5%	5.3%	4.9%	4.0%	3.8%	4.5%	5.0%	3.7%	3.1%	2.9%	2.5%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $2921.1 mill. Due in 5 Yrs $1247.0 mill.
LT Debt $2509.7 mill. LT Interest $145.3 mill.
(LT interest earned: 4.8x)

Leases, Uncapitalized Annual rentals $6.7 mill.

Pension Assets-12/13 $654.9 mill.
Oblig. $658.1 mill.

Pfd Stock None

Common Stock 199,319,096 shs.

MARKET CAP: $7.1 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
4926.6	5948.2	4005.6	3797.6	4070.7	2869.7	3716.9	3915.9	3671.2	2867.7	*2450*	*2550*	Revenues ($mill)	*2950*
157.8	166.1	226.1	244.2	231.4	258.3	295.3	342.9	355.0	387.6	*390*	*420*	Net Profit ($mill)	*510*
34.5%	30.2%	34.8%	32.3%	30.4%	31.7%	34.9%	30.7%	26.0%	24.9%	*32.5%*	*32.5%*	Income Tax Rate	*32.5%*
1.1%	1.3%	3.8%	1.6%	1.7%	9.1%	5.7%	9.0%	2.7%	2.6%	*4.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
52.6%	49.5%	45.6%	44.4%	53.3%	50.6%	50.8%	51.6%	50.7%	43.1%	*46.0%*	*44.0%*	Long-Term Debt Ratio	*45.5%*
47.4%	50.5%	54.4%	55.6%	46.7%	49.4%	49.2%	48.4%	49.3%	56.9%	*54.0%*	*56.0%*	Common Equity Ratio	*54.5%*
2709.7	2726.6	2950.1	3025.5	4058.6	4129.7	4652.5	5300.4	5615.8	5337.2	*6010*	*6240*	Total Capital ($mill)	*7700*
3581.0	3567.4	3867.5	4246.3	5249.8	5911.6	6464.4	7474.0	8344.8	6672.8	*7005*	*7250*	Net Plant ($mill)	*8275*
7.4%	7.6%	9.1%	9.5%	7.0%	7.9%	7.8%	7.8%	7.7%	8.6%	*7.5%*	*8.0%*	Return on Total Cap'l	*8.0%*
12.3%	12.1%	14.1%	14.5%	12.2%	12.7%	12.9%	13.4%	12.8%	12.8%	*12.0%*	*12.0%*	Return on Shr. Equity	*12.0%*
12.3%	12.1%	14.1%	14.5%	12.2%	12.7%	12.9%	13.4%	12.8%	12.8%	*12.0%*	*12.0%*	Return on Com Equity E	*12.0%*
3.4%	3.4%	6.6%	7.1%	5.4%	6.0%	6.7%	7.7%	7.2%	7.3%	*6.0%*	*6.0%*	Retained to Com Eq	*5.5%*
73%	72%	53%	51%	55%	53%	48%	43%	44%	43%	*49%*	*50%*	All Div'ds to Net Prof	*56%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+3.4	-1.8	+1.1
Avg. Indust. Use (MWH)	752	776	779
Avg. Indust. Revs. per KWH (¢)	5.37	5.07	5.44
Capacity at Peak (Mw)	7115	7139	NA
Peak Load, Summer (Mw)	7057	7000	6341
Annual Load Factor (%)	52.2	51.6	NA
% Change Customers (yr-end)	+.8	+1.1	+1.1
Fixed Charge Cov. (%)	427	404	367

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-1.5%	-4.0%	*NMF*
"Cash Flow"	6.5%	8.5%	*2.5%*
Earnings	9.5%	7.5%	*5.5%*
Dividends	2.0%	3.0%	*9.5%*
Book Value	8.0%	8.5%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	840.5	978.1	1212.1	885.2	3915.9
2012	840.7	855.0	1113.4	862.1	3671.2
2013	901.4	734.2	723.2	508.9	2867.7
2014	560.4	611.8	754.7	*523.1*	*2450*
2015	*575*	*625*	*800*	*550*	*2550*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.13	.52	.90	.18	1.73
2012	.19	.47	.94	.19	1.79
2013	.12	.46	1.08	.29	1.94
2014	.25	.50	.94	*.26*	*1.95*
2015	*.20*	*.55*	*1.15*	*.20*	*2.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.18125	.18125	.18125	.18125	.73
2011	.1875	.1875	.1875	.1875	.75
2012	.19625	.19625	.19625	.19625	.79
2013	.20875	.20875	.20875	.20875	.84
2014	.225	.225	.225	.25	

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 813,000 customers in Oklahoma (88% of electric revenues) and western Arkansas (9%); wholesale is (3%). Owns 26.3% of Enable Midstream Partners. Acquired Transok 6/99. Electric revenue breakdown: residential, 42%; commercial, 26%; industrial, 19%; other, 13%. Generating sources: coal, 42%; gas, 32%; wind, 5%; purchased, 21%. Fuel costs: 50% of revenues. '13 reported depreciation rate (utility): 2.8%. Has 2,400 employees. Chairman & CEO: Peter B. Delaney. President: Sean Trauschke. Inc.: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321. Tel.: 405-553-3000. Internet: www.oge.com.

OGE Energy's utility subsidiary is awaiting a ruling from the Oklahoma Corporation Commission on its environmental compliance plan. This plan calls for Oklahoma Gas and Electric to spend $1.1 billion through 2019 to comply with mandates by the U.S. Environmental Protection Agency. OG&E appealed EPA's order, but lost. The utility wants to recover these costs through a rider on customers' bills until they are reflected in base rates. The schedule calls for a decision in March of 2015. Soon thereafter—probably in the second quarter—OG&E will file a general rate case in Oklahoma, with an order due six months later. The utility also plans to file an application in Arkansas in 2015.

Earnings will likely make little (if any) progress in 2014, but we expect improvement in 2015. In most respects, things are going well for OGE. The service area's economy is strong, although it remains to be seen whether the recent drop in oil prices will have a noticeable effect. The formation of Enable Midstream Partners in 2013 and the initial public offering of Enable earlier this year have benefited the company. However, due to mild summer weather, we trimmed our share-earnings estimate by a nickel, to $1.95. That's near the low end of the company's guidance of $1.94-$2.06. We assume normal weather in our 2015 forecast.

The board of directors raised the dividend significantly. In late September, the directors raised the quarterly disbursement by $0.025 a share (11.1%). OGE also stated a goal of raising the dividend 10% annually through 2019. Rising distributions from Enable should enable the board to meet this goal. In the first nine months of 2014, these distributions amounted to $110.1 million.

OGE's share price has risen only 6% year to date. This makes the top-quality stock an outlier in a year in which many utility issues have soared more than 20%. Investors' worries (excessive, in our view) about the effects of lower oil prices on Enable is most probably responsible for the underperformance. The dividend yield is still on the low side for a utility, but 3- to 5-year total return prospects are better than those of most utility equities.

Paul E. Debbas, CFA *December 19, 2014*

(A) Diluted EPS. Excl. nonrecurring losses: '02, 20¢; '03, 7¢; '04, 3¢; gains on discontinued operations: '02, 6¢; '05, 25¢; '06, 20¢. '13 EPS don't add due to rounding. Next earnings report due late Feb. (B) Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan available. (C) Incl. deferred charges. In '13: $1.91/sh. (D) In millions, adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in Oklahoma in '12: 10.2%; in Arkansas in '11: 9.95%; earned on avg. com. eq., '13: 13.2%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	90
Price Growth Persistence	95
Earnings Predictability	95

OTTER TAIL CORP. NDQ-OTTR

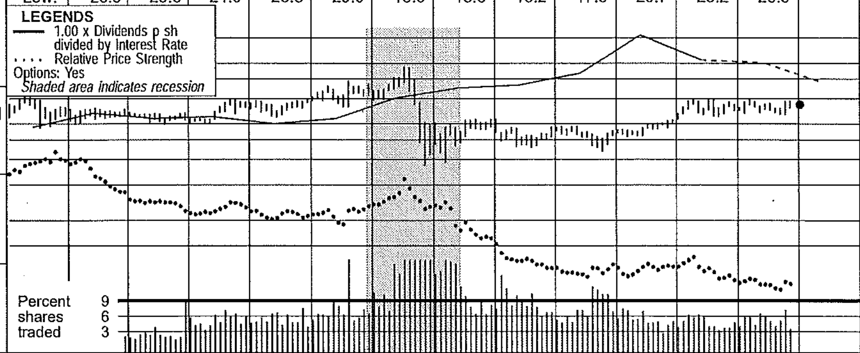
RECENT PRICE 29.90 | P/E RATIO 17.0 (Trailing: 18.2; Median: 23.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Lowered 12/12/14
SAFETY 3 Lowered 12/24/10
TECHNICAL 4 Lowered 12/19/14
BETA .90 (1.00 = Market)

High:	28.9	27.5	32.0	31.9	39.4	46.2	25.4	25.4	23.5	25.3	31.9	31.7
Low:	23.8	23.8	24.0	25.8	29.0	15.0	15.5	18.2	17.5	20.7	25.2	26.5

Target Price Range
2017 | 2018 | 2019

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+35%)	11%
Low	30	(Nil)	4%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	0	2	0	0	0	0	0	1	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	59	51	48
to Sell	39	55	52
Hld's(000)	12156	12279	12308

Percent shares traded 9 6 3

% TOT. RETURN 11/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.5	8.0
3 yr.	52.0	72.4
5 yr.	60.2	119.8

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
18.14	19.48	23.45	26.53	27.75	29.28	30.45	35.59	37.43	41.50	37.06	29.03	31.08	29.86	23.76	24.63	*25.95*	*26.30*	Revenues per sh	*32.50*
2.75	2.91	3.21	3.40	3.44	3.30	2.88	3.35	3.39	3.55	2.81	2.76	2.60	2.36	2.71	3.03	*3.40*	*3.70*	"Cash Flow" per sh	*4.75*
1.29	1.45	1.60	1.68	1.79	1.51	1.50	1.78	1.69	1.78	1.09	.71	.38	.45	1.05	1.37	*1.75*	*1.85*	Earnings per sh A	*2.30*
.96	.99	1.02	1.04	1.06	1.08	1.10	1.12	1.15	1.17	1.19	1.19	1.19	1.19	1.19	1.19	*1.21*	*1.23*	Div'd Decl'd per sh B ■	*1.30*
1.23	1.37	1.85	2.17	2.95	1.97	1.72	2.04	2.35	5.43	7.51	4.95	2.38	2.04	3.20	4.53	*4.45*	*4.45*	Cap'l Spending per sh	*4.75*
9.47	10.30	10.87	11.33	12.25	12.98	14.81	15.80	16.67	17.55	19.14	18.78	17.57	15.83	14.43	14.74	*15.55*	*16.05*	Book Value per sh C	*18.15*
23.76	23.85	23.85	24.65	25.59	25.72	28.98	29.40	29.52	29.85	35.38	35.81	36.00	36.10	36.17	36.27	*37.00*	*38.00*	Common Shs Outst'g D	*40.00*
14.4	13.9	13.5	16.4	16.0	17.8	17.3	15.4	17.3	19.0	30.1	31.2	55.1	47.5	21.7	21.1	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.75	.79	.88	.84	.87	1.01	.91	.82	.93	1.01	1.81	2.08	3.51	2.98	1.38	1.19	*Value Line*		Relative P/E Ratio	*.95*
5.2%	4.9%	4.7%	3.8%	3.7%	4.0%	4.2%	4.1%	3.9%	3.5%	3.6%	5.4%	5.7%	5.6%	5.2%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $537.7 mill. **Due in 5 Yrs** $114.3 mill.
LT Debt $498.5 mill. **LT Interest** $27.0 mill.
(LT interest earned: 3.7x)

Leases, Uncapitalized Annual rentals $8 mill.
Pension Assets-12/13 $213.6 mill. **Oblig.** $254.0 mill.
Pfd Stock None

Common Stock 36,806,160 shs.
as of 10/31/14
MARKET CAP: $1.1 billion (Mid Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
882.3	1046.4	1105.0	1238.9	1311.2	1039.5	1119.1	1077.9	859.2	893.3	*960*	*1000*	Revenues ($mill)	*1300*
40.0	52.9	50.8	54.0	35.1	26.0	13.6	16.4	39.0	50.2	*65.0*	*70.0*	Net Profit ($mill)	*90.0*
29.8%	34.6%	34.8%	34.1%	30.0%	--	--	14.5%	5.2%	21.3%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
2.4%	1.7%	1.9%	4.2%	6.1%	4.0%	.6%	3.8%	1.7%	3.6%	*3.0%*	*4.0%*	AFUDC % to Net Profit	*5.0%*
37.1%	35.0%	33.5%	38.9%	32.9%	38.8%	40.2%	44.6%	44.0%	42.1%	*47.5%*	*48.5%*	Long-Term Debt Ratio	*49.0%*
60.7%	62.9%	64.5%	59.4%	65.6%	59.8%	58.4%	54.0%	54.4%	57.9%	*52.5%*	*51.5%*	Common Equity Ratio	*51.0%*
706.5	738.2	763.0	882.1	1032.5	1124.4	1083.3	1058.9	959.2	924.4	*1100*	*1185*	Total Capital ($mill)	*1425*
682.1	697.1	718.6	854.0	1037.6	1098.6	1108.7	1077.5	1049.5	1167.0	*1275*	*1350*	Net Plant ($mill)	*1600*
6.8%	8.3%	7.7%	7.2%	4.3%	3.4%	2.7%	3.2%	5.7%	6.6%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.5%*
9.0%	11.0%	10.0%	10.0%	5.1%	3.8%	2.1%	2.8%	7.3%	9.4%	*11.5%*	*11.5%*	Return on Shr. Equity E	*12.5%*
9.1%	11.2%	10.2%	10.2%	5.1%	3.8%	2.0%	2.7%	7.3%	9.4%	*11.5%*	*11.5%*	Return on Com Equity	*12.5%*
2.5%	4.2%	3.3%	3.5%	NMF	NMF	NMF	NMF	NMF	1.2%	*3.5%*	*3.5%*	Retained to Com Eq	*5.0%*
73%	63%	68%	66%	108%	NMF	NMF	NMF	113%	87%	*70%*	*68%*	All Div'ds to Net Prof	*59%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+.6	-1.1	+5.8
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	146	257	359

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	1.0%	-6.0%	*3.5%*
"Cash Flow"	-2.5%	-5.5%	*10.0%*
Earnings	-9.5%	-18.5%	*15.5%*
Dividends	1.5%	.5%	*1.5%*
Book Value	3.5%	-1.0%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	249.1	283.3	282.4	263.1	1077.9
2012	219.9	211.4	215.3	212.6	859.2
2013	218.0	212.4	229.8	233.1	893.3
2014	240.5	234.6	242.4	*242.5*	*960*
2015	*248*	*242*	*255*	*255*	*1000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.14	.14	.20	d.03	.45
2012	.28	.19	.13	.47	1.05
2013	.41	.21	.41	.35	1.37
2014	.59	.27	.43	*.46*	*1.75*
2015	*.55*	*.32*	*.50*	*.48*	*1.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.298	.298	.298	.298	1.19
2011	.298	.298	.298	.298	1.19
2012	.298	.298	.298	.298	1.19
2013	.298	.298	.298	.298	1.19
2014	.303	.303	.303	.303	

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to over 130,000 customers in Minnesota (48% of retail elec. revs.), North Dakota (43%), and South Dakota (9%). Electric rev. breakdown, '13: residential, 33%; commercial & farms, 37%; industrial, 23%; other, 7%. Fuel costs: 13.8% of revenues. Also has operations in manufacturing, construction, and plastics. 2013 depr. rate: 3.2%. Has 2,336 employees. Off. and dir. own 1.4% of common stock; Cascade Investment, LLC, 9.5%; Vanguard Group, Inc., 6.5%; BlackRock, Inc., 5.7% (2/14 Proxy). CEO: Edward McIntyre. Inc.: MN. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, Minnesota 56538-0496. Telephone: 866-410-8780. Internet: www.ottertail.com.

Shares of Otter Tail have traded somewhat higher over the past three months. The company reported solid performance for the third quarter. The electric line benefited from higher net cost recovery rider revenue, an increase in fuel clause adjustment revenue, and greater sales to pipeline customers. This was partly offset by the impact of milder weather and lower wholesale electric revenue. Meanwhile, the Manufacturing unit's BTD subsidiary reported higher sales to customers in recreational, lawn and garden, and energy-related end markets. Elsewhere, the Plastics line benefited from an increase in demand for polyvinyl chloride (PVC) pipe. The top line declined in the Construction segment, though earnings improved on higher margins. Overall, revenues and share earnings advanced moderately, on a year-over-year basis. We expect favorable comparisons for the fourth quarter, and healthy growth for the company for full-year 2014.

Revenues and earnings will probably continue to advance from 2015 onward. The Electric segment should be able to further capitalize on a healthy operating climate in the coming quarters. This line will likely continue to experience growth in retail kilowatt-hour sales and rider recovery revenue going forward. Meanwhile, good performance ought to continue at the Manufacturing unit's BTD operation, though this will likely be partly offset by less favorable results at subsidiary T.O. Plastics. Elsewhere, the Construction business ought to gain from demand for electric transmission and distribution work, more-selective bidding on projects, and improved cost control processes. In addition, the Plastics segment should further benefit from healthy customer demand for PVC pipe. However, earnings here could well remain soft, as greater resin costs may not be fully recovered through increased pipe prices.

This stock is ranked to track the broader equity market for the coming six to 12 months. Looking further out, this issue is not a standout for long-term appreciation potential, from the recent quotation. Nevertheless, income-oriented investors may find the healthy dividend yield attractive.

Michael Napoli, CFA *December 19, 2014*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '98, 7¢; '99, 34¢; '10, (44¢); '11, 26¢; '13, 2¢; gains (losses) from discont. operations: '04, 8¢; '05, 33¢; '06, 1¢; '11, ($1.11); '12, ($1.22). Earnings may not sum due to rounding. Next earnings report due in February. (B) Div'ds historically paid in early March, June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intangibles. In '13: $52.3 mill., $1.44/sh. (D) In mill. (E) Regulatory Climate: MN, ND, Average; SD, Above Average.

Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	20
Earnings Predictability	50

Staff/209
Muldoon/31

PEPCO HOLDINGS NYSE-POM

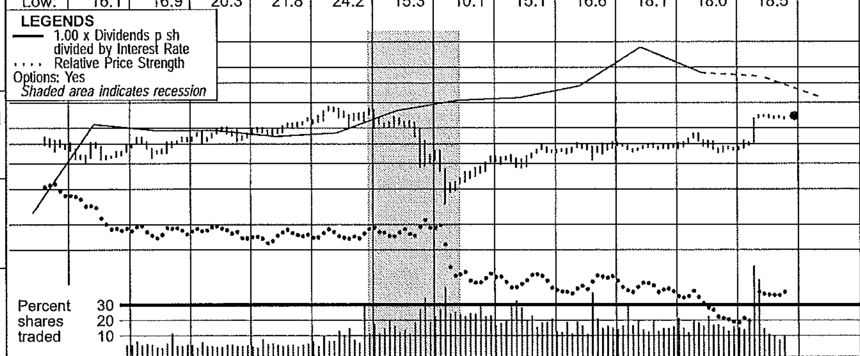
RECENT PRICE 27.51 | P/E RATIO 20.5 (Trailing: 21.5 / Median: 15.0) | RELATIVE P/E RATIO 1.13 | DIV'D YLD 3.9% | VALUE LINE

High:	20.6	21.7	24.5	27.0	30.7	29.6	18.7	19.8	20.6	20.5	22.7	27.9
Low:	16.1	16.9	20.3	21.8	24.2	15.3	10.1	15.1	16.6	18.1	18.0	18.5

TIMELINESS – Suspended 5/9/14
SAFETY 3 Lowered 6/6/03
TECHNICAL – Suspended 5/9/14
BETA .70 (1.00 = Market)

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2017 | 2018 | 2019



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+10%)	5%
Low	20	(-25%)	-3%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2013	1Q2014	2Q2014
to Buy	167	155	160
to Sell	138	157	176
Hld's(000)	144455	148709	153156

Percent shares traded 30 20 10

% TOT. RETURN 10/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	48.7	10.1
3 yr.	61.7	67.5
5 yr.	142.0	124.6

Pepco Holdings, Inc. (PHI) was formed on August 1, 2002, upon the merger of Potomac Electric Power Co. (PEPCO) and Conectiv. In the $2.2 billion deal, PEPCO common stockholders received one common share in PHI for each of their shares, and Conectiv investors exchanged each of their common shares for $25 worth of PHI stock and cash, prorated 50/50.

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
38.35	42.49	43.57	46.71	48.88	41.66	31.27	26.02	22.09	18.64	**19.85**	**21.25**	Revenues per sh	**25.40**
3.71	3.67	3.47	3.30	3.55	2.82	2.97	3.00	3.21	3.01	**3.25**	**3.45**	"Cash Flow" per sh	**3.75**
1.46	1.49	1.33	1.53	1.93	1.06	1.24	1.14	1.24	1.14	**1.25**	**1.45**	Earnings per sh A	**1.75**
1.00	1.00	1.04	1.04	1.08	1.08	1.08	1.08	1.08	1.08	**1.08**	**1.08**	Div'd Decl'd per sh B ■	**1.08**
2.75	2.46	2.47	3.11	3.57	3.89	3.56	4.14	5.29	5.23	**5.20**	**5.20**	Cap'l Spending per sh	**4.00**
17.87	18.88	18.82	20.04	19.14	19.15	18.79	19.06	19.33	17.24	**19.45**	**20.10**	Book Value per sh C	**21.90**
188.33	189.82	191.93	200.51	218.91	222.27	225.08	227.50	230.02	250.32	**252.00**	**254.00**	Common Shs Outst'g D	**260.00**
13.6	14.9	18.1	18.2	12.2	13.7	14.0	16.7	15.6	17.5	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	**14.0**
.72	.79	.98	.97	.73	.91	.89	1.05	.99	.98			Relative P/E Ratio	**.90**
5.0%	4.5%	4.3%	3.7%	4.6%	7.4%	6.2%	5.7%	5.6%	5.4%			Avg Ann'l Div'd Yield	**4.9%**
7221.8	8065.5	8362.9	9366.4	10700	9259.0	7039.0	5920.0	5081.0	4666.0	**5000**	**5400**	Revenues ($mill)	**6600**
261.3	277.4	254.4	296.5	400.0	235.0	276.0	257.0	285.0	280.0	**315**	**370**	Net Profit ($mill)	**455**
38.7%	38.8%	39.1%	39.3%	29.6%	31.9%	18.8%	37.2%	35.4%	35.3%	**35.0%**	**35.0%**	Income Tax Rate	**35.0%**
--	--	--	--	--	--	--	10.1%	7.4%	6.4%	**6.0%**	**5.0%**	AFUDC % to Net Profit	**4.0%**
59.7%	57.1%	54.6%	54.1%	56.2%	53.8%	49.0%	49.1%	47.3%	48.4%	**47.5%**	**47.5%**	Long-Term Debt Ratio	**49.5%**
39.6%	42.3%	45.1%	45.9%	43.8%	46.2%	51.0%	50.9%	52.7%	51.6%	**52.5%**	**52.5%**	Common Equity Ratio	**50.5%**
8494.0	8469.3	8004.0	8753.0	9568.0	9203.0	8292.0	8516.0	8432.0	8668.0	**9300**	**9700**	Total Capital ($mill)	**11500**
7088.0	7312.0	7576.6	7876.7	8314.0	8863.0	7673.0	8220.0	8846.0	9704.0	**10000**	**10500**	Net Plant ($mill)	**12000**
5.0%	5.0%	5.1%	5.1%	5.8%	4.5%	5.1%	4.5%	4.9%	4.9%	**4.5%**	**5.0%**	Return on Total Cap'l	**5.5%**
7.6%	7.6%	7.0%	7.4%	9.5%	5.5%	6.5%	5.9%	6.4%	6.5%	**6.5%**	**7.5%**	Return on Shr. Equity	**8.0%**
7.7%	7.7%	7.0%	7.4%	9.5%	5.5%	6.5%	5.9%	6.4%	6.5%	**6.5%**	**7.5%**	Return on Com Equity E	**8.0%**
2.5%	2.4%	1.5%	2.3%	4.2%	NMF	.8%	.3%	.8%	.2%	**.5%**	**1.5%**	Retained to Com Eq	**2.5%**
68%	69%	78%	68%	56%	101%	87%	95%	87%	96%	**90%**	**77%**	All Div'ds to Net Prof	**69%**

CAPITAL STRUCTURE as of 9/30/14
Total Debt $5750 mill. **Due in 5 Yrs** $1612 mill.
LT Debt $4691 mill. **LT Interest** $260 mill.
(LT interest earned: 3.7x)

Pension Assets-12/13 $2.0 bill. **Oblig.** $2.2 bill.

Pfd Stock None

Common Stock 251,907,108 shs.
as of 10/20/14

MARKET CAP: $6.9 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-2.8	NA	NA
Avg. Resid'l Use (KWH)	10836	10451	10405
Avg. Resid'l Revs. per KWH(¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+.3	+.6
Fixed Charge Cov. (%)	251	253	246

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-6.5%	-13.5%	2.0%
"Cash Flow"	-2.5%	-2.0%	3.5%
Earnings	-4.0%	-6.0%	7.0%
Dividends	8.5%	.5%	0.0%
Book Value	.5%	-1.0%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	1634	1409	1643	1234	5920.0
2012	1292	1179	1476	1134	5081.0
2013	1178	1053	1344	1091	4666.0
2014	1330	1117	1313	*1240*	*5000*
2015	*1350*	*1200*	*1500*	*1350*	*5400*

Cal-endar	EARNINGS PER SHARE A F Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.28	.42	.35	.09	1.14
2012	.30	.27	.49	.18	1.24
2013	.24	.22	.44	.24	1.14
2014	.30	.21	.44	*.30*	*1.25*
2015	*.30*	*.30*	*.55*	*.30*	*1.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.27	.27	.27	.27	1.08
2011	.27	.27	.27	.27	1.08
2012	.27	.27	.27	.27	1.08
2013	.27	.27	.27	.27	1.08
2014	.27	.27	.27		

BUSINESS: Pepco Holdings, Inc. consists mainly of three electric utility subsidiaries: Potomac Electric Power Co., serving Washington, D.C. and adjoining areas of Maryland; Delmarva Power, which serves the peninsula area of Delaware, Maryland and Virginia; and Atlantic City Electric, serving southern New Jersey. In July 2010, Pepco sold competitive energy business (Conectiv Energy) to Calpine Corp. Electricity customers: 1.8 million; gas customers: 125,000. Electricity breakdown: residential, 40%; commercial, 41%; other, 19%. 2013 depreciation rate: 2.5%. Has approximately 5,025 employees as of 12/31/12. Chrmn., Pres. & CEO: Joseph M. Rigby. Inc.: DE. Address: 701 Ninth Street, N.W., Wash., D.C. 20068. Telephone.: 202-872-2000. Internet: www.pepcoholdings.com.

The takeover of Pepco Holdings by Exelon Corporation is making progress, and it is expected to be completed by the second or third quarter of 2015. The all-cash transaction of approximately $6.8 billion, in which Chicago-based Exelon will pay Pepco Holdings owners $27.25 a share was announced earlier in April. The proposed merger was approved by shareholders of Pepco on September 23rd. Further, the State Corporation Commission of Virginia also endorsed the union earlier this month, allowing the deal to move another step closer toward completion. However, the transaction is still subject to certain closing conditions and remaining regulatory approval by the Federal Energy Regulatory Commission, and public service commissions in New Jersey, Maryland, Delaware, and the District of Columbia. The State Commission of Maryland is currently expected to begin hearings starting in January 2015.

Multi-jurisdictional merger approvals are complex. Pepco Holdings currently owns utilities in Delaware, Maryland, New Jersey, and the District of Columbia. It is expected to complement the utilities that Exelon owns including Philadelphia's PECO Energy Co. and Baltimore Gas and Electric. In order to gain regulatory approval the two companies have agreed to offer $100 million in customer benefits. Still, there is no guarantee that the deal will go through. The combined entity would serve approximately 10 million customers in the midwest and mid-Atlantic regions, and state regulators would have to find that the new company will provide direct and tangible benefits to the customers.

Management has narrowed its guidance for 2014. The earlier guidance range for 2014 of $1.12-$1.27 per share was revised to $1.17-$1.27 per share. Our share net estimate of $1.25 is at the higher end of this range.

Due to the impending acquisition by Exelon Corporation, the Timeliness rank for this equity stays suspended. This stock is currently trading above the purchase price of $27.25. To eliminate any downside risk in case the deal falls through, we suggest investors sell their holdings at the prevailing price.

Saumya Ajila *November 21, 2014*

(A) Based on dil. shs. Excl. nonrecur. items: '03, d69¢; '04, 1¢; '05, 47¢; '06, d1¢; '08, 46¢; '10, 62¢ '13, 69¢. Next egs. rpt. due late Feb. (B) Div'ds paid in early March, June, Sep., and Dec. ■ Div'd reinvest. plan. (C) Incl. def'd chgs: '12, $4.8 bill. or $20.87/sh. (D) In mill. (E) Rate allowed in MD: 9.36% ('13-Pepco), 10.0% ('09-Delmarva); DC: 9.6% ('10-Pep.); DEL: 10.0% ('06-Del.); NJ: 9.75% ('13-ACE); Earned on '13 avg. com. eq., 6.5%. Reg. Clim.: Avg. (F) Qtrly egs. may not add due to chng. in shs.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	15
Earnings Predictability	70

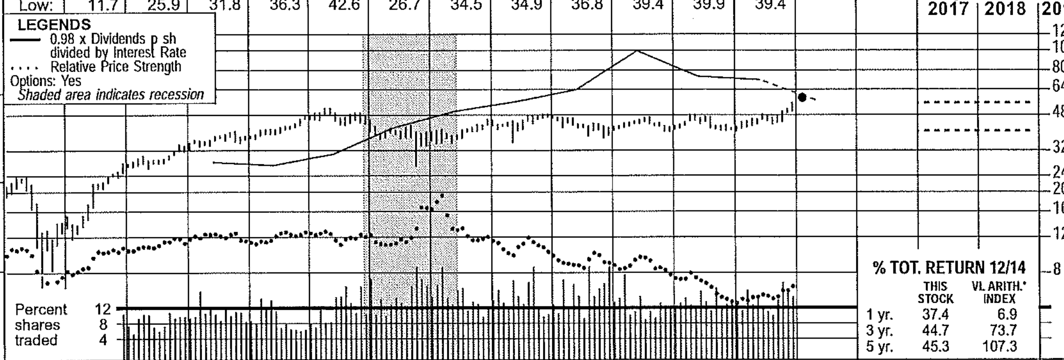
PG&E CORP. NYSE-PCG

RECENT PRICE 58.30 | P/E RATIO 16.9 (Trailing: 19.7; Median: 15.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 3 Lowered 12/19/14
SAFETY 3 Lowered 2/3/12
TECHNICAL 3 Raised 11/28/14
BETA .65 (1.00 = Market)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
High:	28.0	34.5	40.1	48.2	52.2	45.7	45.8	48.6	48.0	47.0	48.5	55.2
Low:	11.7	25.9	31.8	36.3	42.6	26.7	34.5	34.9	36.8	39.4	39.9	39.4

LEGENDS
—— 0.98 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(-5%)	2%
Low	40	(-30%)	-4%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	1	0	0
to Sell	0	6	0	1	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	217	206	210
to Sell	203	205	186
Hld's(000)	370504	387652	390623

Percent shares traded 12 8 4

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	37.4	6.9
3 yr.	44.7	73.7
5 yr.	45.3	107.3

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
52.12	57.74	67.75	63.18	32.74	25.05	26.47	31.78	36.02	37.42	40.51	36.15	35.02	36.28	34.92	34.16	35.50	35.90	Revenues per sh	41.00
6.08	7.15	.80	5.66	1.14	4.80	5.71	7.12	7.76	8.02	8.44	8.37	8.22	8.08	7.32	6.33	7.95	7.95	"Cash Flow" per sh	9.25
1.88	2.24	d9.21	3.02	d2.36	2.05	2.12	2.35	2.76	2.78	3.22	3.03	2.82	2.78	2.07	1.83	3.15	2.95	Earnings per sh A	3.50
1.20	1.20	1.20	--	--	--	--	1.23	1.32	1.44	1.56	1.68	1.82	1.82	1.82	1.82	1.82	1.82	Div'd Decl'd per sh B ■ †	2.10
4.23	4.39	4.54	7.33	7.94	4.08	3.72	4.90	6.90	7.83	10.05	10.68	9.62	9.79	10.74	11.40	10.70	11.35	Cap'l Spending per sh	11.25
21.08	19.10	8.19	11.89	9.47	10.12	20.62	19.60	22.44	24.18	25.97	27.88	28.55	29.35	30.35	31.41	33.25	34.60	Book Value per sh C	39.25
382.60	360.59	387.19	363.38	381.67	416.52	418.62	368.27	348.14	353.72	361.06	370.60	395.23	412.26	430.72	456.67	476.00	485.00	Common Shs Outst'g D	500.00
16.8	13.1	--	4.8	--	9.5	13.8	15.4	14.8	16.8	12.1	13.0	15.8	15.5	20.7	23.7	14.6		Avg Ann'l P/E Ratio	13.5
.87	.75	--	.25	--	.54	.73	.82	.80	.89	.73	.87	1.01	.97	1.32	1.33	.75		Relative P/E Ratio	.85
3.8%	4.1%	4.8%	--	--	--	--	3.4%	3.2%	3.1%	4.0%	4.3%	4.1%	4.2%	4.2%	4.2%	4.0%		Avg Ann'l Div'd Yield	4.4%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $14981 mill. **Due in 5 yrs** $2849 mill.
LT Debt $14555 mill. **LT Interest** $720 mill.
Incl. $90 mill. capitalized leases.
(LT interest earned: 3.4x)
Pension Assets-12/13 $12527 mill.
Oblig. $14077 mill.
Pfd Stock $252 mill. **Pfd Div'd** $14 mill.
4,534,958 shs. 4.36% to 5%, cumulative and $25 par, redeemable from $25.75 to $27.25; 5,784,825 shs. 5.00% to 6.00%, cumulative nonredeemable and $25 par.
Common Stock 475,088,027 shs. **as of 10/20/14**
MARKET CAP: $28 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
11080	11703	12539	13237	14628	13399	13841	14956	15040	15598	16900	17400	Revenues ($mill)	20500
901.0	904.0	1005.0	1020.0	1198.0	1168.0	1113.0	1132.0	893.0	828.0	1495	1445	Net Profit ($mill)	1830
35.0%	37.6%	35.5%	34.6%	26.2%	31.1%	33.0%	30.3%	23.9%	24.5%	20.0%	25.0%	Income Tax Rate	26.5%
3.6%	5.6%	6.7%	9.4%	9.5%	11.9%	14.4%	11.2%	17.5%	17.9%	9.0%	10.0%	AFUDC % to Net Profit	8.0%
45.1%	48.3%	51.7%	52.6%	52.2%	51.4%	49.6%	48.8%	48.7%	46.6%	48.0%	47.5%	Long-Term Debt Ratio	49.5%
53.2%	50.0%	46.8%	46.1%	46.5%	47.4%	49.3%	50.2%	50.4%	52.5%	51.5%	52.0%	Common Equity Ratio	50.0%
16242	14446	16696	18558	20163	21793	22863	24119	25956	27311	30850	32375	Total Capital ($mill)	39200
18989	19955	21785	23656	26261	28892	31449	33655	37523	41252	44050	47125	Net Plant ($mill)	56000
7.6%	8.1%	7.6%	7.4%	7.8%	6.7%	6.2%	5.9%	4.7%	4.2%	6.0%	5.5%	Return on Total Cap'l	6.0%
10.1%	12.1%	12.5%	11.6%	12.4%	11.0%	9.6%	9.2%	6.7%	5.7%	9.5%	8.5%	Return on Shr. Equity	9.0%
10.3%	12.3%	12.7%	11.8%	12.6%	11.2%	9.7%	9.2%	6.7%	5.7%	9.5%	8.5%	Return on Com Equity E	9.5%
10.3%	7.7%	6.8%	6.0%	6.8%	5.5%	3.9%	3.4%	1.0%	.2%	4.0%	3.5%	Retained to Com Eq	4.0%
1%	39%	47%	50%	47%	52%	61%	63%	85%	96%	58%	61%	All Div'ds to Net Prof	58%

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-.3	+6.0	+.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	9.51	9.17	9.28
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.4	+.5	+.3
Fixed Charge Cov. (%)	295	231	223

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-1.5%	-1.5%	2.5%
"Cash Flow"	6.5%	-2.0%	4.0%
Earnings	9.5%	-5.5%	8.0%
Dividends	--	5.0%	2.5%
Book Value	11.0%	4.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	3597	3684	3860	3815	14956
2012	3641	3593	3976	3830	15040
2013	3672	3776	4175	3975	15598
2014	3891	3952	4939	4118	16900
2015	4150	4150	4850	4250	17400

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.50	.91	.68	.69	2.78
2012	.66	.55	.87	d.01	2.07
2013	.55	.74	.36	.19	1.83
2014	.49	.57	1.71	.38	3.15
2015	.65	.70	1.05	.55	2.95

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.455	.455	.455	.455	1.82
2012	.455	.455	.455	.455	1.82
2013	.455	.455	.455	.455	1.82
2014	.455	.455	.455	.455	1.82
2015	.455				

BUSINESS: PG&E Corporation is a holding company for Pacific Gas and Electric Company and nonutility subsidiaries. Supplies electricity and gas to most of northern and central California. Has 5.3 million electric and 4.4 million gas customers. Electric revenue breakdown: residential, 41%; commercial, 39%; industrial, 11%; agricultural, 8%; other, 1%. Generating sources: nuclear, 24%; hydro, 11%; gas, 8%; purchased, 57%. Fuel costs: 38% of revenues. '13 reported depreciation rate (utility): 3.5%. Has 21,200 employees. Chairman, President & Chief Executive Officer: Anthony F. Earley, Jr. Incorporated: California. Address: One Market, Spear Tower, Suite 2400, San Francisco, California 94105. Telephone: 415-267-7000. Internet: www.pgecorp.com.

Will 2015 be the year in which the uncertainties surrounding the explosion of a PG&E gas pipeline in San Bruno, California are finally resolved? In September of 2010, the accident killed eight people, injured dozens more, and caused extensive property damage. Since then, the company has incurred (and continues to do so) significant pipeline-related expenses that were not recovered from customers. These costs are *included* in our earnings presentation, but a $200 million reserve PG&E took for a probable fine was excluded. All told, the company has incurred (or committed to do so) $2.7 billion in unrecovered costs. However, administrative law judges and the Safety and Enforcement Division of the California Public Utilities Commission (CPUC) are each recommending additional penalties that would raise the negative pretax impact on shareholders to more than $4.7 billion. The company is also facing an indictment from the federal government.

Earnings are tough to predict. This is due to uncertainties in the magnitude and timing of the unrecovered costs, as well as any insurance recoveries. (Note that our Earnings Predictability score includes data from years before the accident.)

Wall Street appears optimistic that this problem will be resolved without excessive harm to the company's finances. The share price rose more than 25% in 2014, and has advanced almost 10% so far in the new year.

PG&E awaits a ruling on its gas transmission and storage case. The utility requested increases of $555 million in 2015, $61 million in 2016, and $168 million in 2017. New rates will be retroactive to the start of this year. However, the discovery of some *ex parte* communications (via e-mail) between the company and the CPUC might well complicate this matter.

We believe more-attractive selections are available elsewhere. Following the run-up in the stock price, the dividend yield is a bit below average for a utility. The payout hasn't been raised since the accident, and we expect no hike again in 2015, even if the San Bruno matter with the CPUC is concluded before yearend. Finally, the recent price is above the upper end of our 2017-2019 Target Price Range.

Paul E. Debbas, CFA *January 30, 2015*

(A) Diluted EPS. Excl. nonrec. gains (losses): '99, ($2.44); '04, $6.95; '09, 18¢; '11, (68¢); '12, (15¢); gain from disc. ops.: '08, 41¢. Incl. nonrec. loss: '00, $11.83. '13 EPS don't add due to rounding. Next earnings report due mid-Feb. (B) Div'ds historically paid in mid-Jan., Apr., July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder investment plan avail. (C) Incl. intang. In '13: $10.76/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '13: 10.4%; earned on avg. com. eq., '13: 5.9%. Regulatory Climate: Above Average.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	70

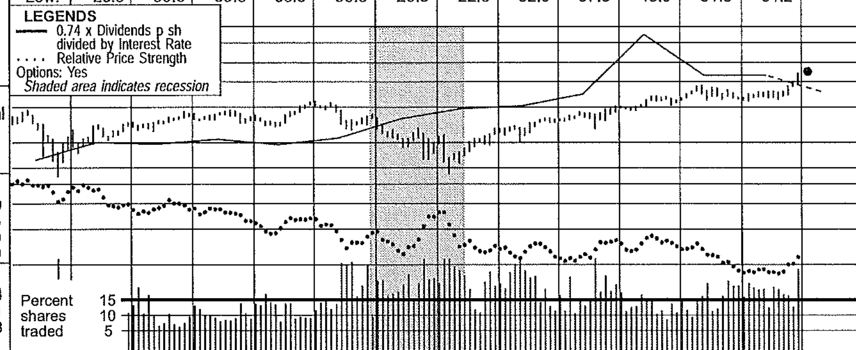
PINNACLE WEST NYSE-PNW

RECENT PRICE 71.96 | P/E RATIO 18.8 (Trailing: 19.2 / Median: 15.0) | RELATIVE P/E RATIO 1.02 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 Lowered 10/10/14
SAFETY 1 Raised 5/3/13
TECHNICAL 3 Raised 12/12/14
BETA .70 (1.00 = Market)

High:	40.5	45.8	46.7	51.0	51.7	42.9	38.0	42.7	48.9	54.7	61.9	71.1
Low:	28.3	36.3	39.8	38.3	36.8	26.3	22.3	32.3	37.3	45.9	51.5	51.2

LEGENDS
—— 0.74 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2017 | 2018 | 2019

120 / 100 / 80 / 64 / 48 / 32 / 24 / 20 / 16 / 12 / 8

2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(-10%)	*1%*
Low	55	(-25%)	*-2%*

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	160	169	171
to Sell	177	171	163
Hld's(000)	87519	87807	88791

Percent shares traded 15 / 10 / 5

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	34.5	6.9
3 yr.	60.0	73.7
5 yr.	133.7	107.3

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
25.12	28.57	43.50	53.66	28.90	30.87	31.59	30.16	34.03	35.07	33.37	32.50	30.01	29.67	30.09	31.35	*31.40*	*32.35*	Revenues per sh	*35.25*
7.34	7.73	7.99	8.72	7.01	7.33	6.93	5.76	9.70	9.29	8.13	8.08	6.85	7.52	7.92	8.15	*8.35*	*8.75*	"Cash Flow" per sh	*9.75*
2.85	3.18	3.35	3.68	2.53	2.52	2.58	2.24	3.17	2.96	2.12	2.26	3.08	2.99	3.50	3.66	*3.70*	*3.85*	Earnings per sh A	*4.25*
1.23	1.33	1.43	1.53	1.63	1.73	1.83	1.93	2.03	2.10	2.10	2.10	2.10	2.10	2.67	2.23	2.33	*2.44*	Div'd Decl'd per sh B ■	*2.80*
3.76	4.05	7.76	12.27	9.81	7.60	5.86	6.39	7.59	9.37	9.46	7.64	7.03	8.26	8.24	9.36	*9.10*	*9.55*	Cap'l Spending per sh	*9.25*
25.50	26.00	28.09	29.46	29.44	31.00	32.14	34.57	34.48	35.15	34.16	32.69	33.86	34.98	36.20	38.07	*39.45*	*40.85*	Book Value per sh C	*45.50*
84.83	84.83	84.83	84.83	91.26	91.29	91.79	99.08	99.96	100.49	100.89	101.43	108.77	109.25	109.74	110.18	*110.75*	*111.25*	Common Shs Outst'g D	*117.50*
15.2	11.9	11.3	12.0	14.4	14.0	15.8	19.2	13.7	14.9	16.1	13.7	12.6	14.6	14.3	15.3	*15.4*		Avg Ann'l P/E Ratio	*13.5*
.79	.68	.73	.61	.79	.80	.83	1.02	.74	.79	.97	.91	.80	.92	.91	.86	*.80*		Relative P/E Ratio	*.85*
2.8%	3.5%	3.8%	3.5%	4.5%	4.9%	4.5%	4.5%	4.7%	4.8%	6.2%	6.8%	5.4%	4.8%	5.3%	4.0%	4.1%		Avg Ann'l Div'd Yield	*4.8%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $3525.8 mill. **Due in 5 Yrs** $1528.1 mill.
LT Debt $3037.8 mill. **LT Interest** $159.6 mill.
Incl. $13.4 mill. Palo Verde sale leaseback lessor notes.
(LT interest earned: 4.5x)
Leases, Uncapitalized Annual rentals $20.0 mill.
Pension Assets-12/13 $2264.1 mill. **Oblig.** $2646.5 mill.
Pfd Stock None

Common Stock 110,450,009 shs.
as of 10/24/14
MARKET CAP: $7.9 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
2899.7	2988.0	3401.7	3523.6	3367.1	3297.1	3263.6	3241.4	3301.8	3454.6	*3475*	*3600*	Revenues ($mill)	*4150*
235.2	223.2	317.1	298.8	213.6	229.2	330.4	328.2	387.4	406.1	*415*	*430*	Net Profit ($mill)	*505*
35.4%	36.2%	33.0%	33.6%	23.4%	36.9%	31.9%	34.0%	36.2%	34.4%	*34.0%*	*35.0%*	Income Tax Rate	*35.0%*
6.9%	10.4%	11.1%	14.8%	17.5%	11.2%	11.7%	12.8%	9.7%	10.0%	*10.0%*	*9.0%*	AFUDC % to Net Profit	*8.0%*
46.7%	43.2%	48.4%	47.0%	46.8%	50.4%	45.3%	44.1%	44.6%	40.0%	*42.0%*	*46.5%*	Long-Term Debt Ratio	*41.0%*
53.3%	56.8%	51.6%	53.0%	53.2%	49.6%	54.7%	55.9%	55.4%	60.0%	*58.0%*	*53.5%*	Common Equity Ratio	*59.0%*
5535.2	6033.4	6678.7	6658.7	6477.6	6686.6	6729.1	6840.9	7171.9	6990.9	*7545*	*8465*	Total Capital ($mill)	*9100*
7535.5	7577.1	7881.9	8436.4	8916.7	9257.8	9578.8	9962.3	10396	10889	*11385*	*11910*	Net Plant ($mill)	*13575*
5.6%	5.0%	6.2%	5.9%	4.7%	4.8%	6.5%	6.4%	6.8%	7.1%	*6.5%*	*6.0%*	Return on Total Cap'l	*6.5%*
8.0%	6.5%	9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
8.0%	6.5%	9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	*9.5%*	*9.5%*	Return on Com Equity E	*9.5%*
2.3%	1.0%	3.4%	2.5%	.3%	.7%	3.1%	2.8%	4.1%	4.1%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
71%	85%	63%	70%	96%	89%	66%	68%	58%	58%	*62%*	*63%*	All Div'ds to Net Prof	*65%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+1.8	-.2	-.2
Avg. Indust. Use (MWH)	632	647	644
Avg. Indust. Revs. per KWH (¢)	7.78	7.86	8.21
Capacity at Peak (Mw)	8577	8864	8398
Peak Load, Summer (Mw)	7087	7207	6927
Annual Load Factor (%)	50.0	48.8	50.0
% Change Customers (yr-end)	+.8	+1.3	+1.4
Fixed Charge Cov. (%)	308	397	419

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-2.0%	-2.5%	*2.5%*
"Cash Flow"	--	-3.0%	*3.5%*
Earnings	1.5%	4.0%	*4.0%*
Dividends	3.5%	2.5%	*3.0%*
Book Value	2.0%	1.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	648.9	799.8	1124.8	667.9	3241.4
2012	620.6	878.6	1109.5	693.1	3301.8
2013	686.6	915.8	1152.4	699.8	3454.6
2014	686.3	906.3	1172.7	*709.7*	*3475*
2015	*700*	*950*	*1200*	*750*	*3600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	d.15	.78	2.24	.11	2.99
2012	d.07	1.12	2.21	.24	3.50
2013	.22	1.18	2.04	.22	3.66
2014	.14	1.19	2.20	*.17*	*3.70*
2015	*.20*	*1.25*	*2.20*	*.20*	*3.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.525	.525	.525	.525	2.10
2012	.525	.525	.525	.545	2.12
2013	.545	.545	.545	.5675	2.20
2014	.5675	.5675	.5675	.595	2.30
2015					

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.1 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 49%; commercial, 39%; industrial, 5%; other, 7%. Generating sources: coal, 33%; nuclear, 27%; gas & other, 18%; purchased, 22%. Fuel costs: 32% of revenues. Has 6,400 employees. '13 reported deprec. rate: 3.0%. Chairman, President & CEO: Donald E. Brandt. Inc.: AZ. Address: 400 North Fifth St., P.O. Box 53999, Phoenix, AZ 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West's utility subsidiary received a rate increase that took effect at the start of the new year. Arizona Public Service paid $182 million for a 739-megawatt stake in Units 4 and 5 of the Four Corners coal-fired plant. (It retired Units 1, 2, and 3.) In order to place these assets into the rate base, the utility's tariffs were raised by $57.1 million (2.0%). The increase was below the $65.4 million that APS had sought.

The utility will put forth a regulatory filing this year to address rate design. Like many utilities, APS believes customers that have installed solar panels on their buildings are not paying for their use of the electric grid. The Arizona Corporation Commission (ACC) has opened a generic docket to address this matter. The ACC has two new members, but this isn't likely to slow the regulatory process.

We estimate that earnings will increase 4% this year. The aforementioned rate increase should help. APS also receives rate relief annually for certain kinds of capital spending, such as for transmission. Customer growth is improving as the state's economy recovers from the real estate collapse that occurred several years ago. Our 2015 share-earnings estimate is at the midpoint of Pinnacle West's targeted range of $3.75-$3.95.

The utility is planning to add some gas-fired generating capacity. APS intends to build 510 mw and retire 220 mw, for net incremental capacity of 290 mw. The ACC has approved the project. The company expects the project to be completed in the second quarter of 2018 at a cost of $60 million-$70 million.

Finances are strong. The fixed-charge coverage and common-equity ratio are well above the utility norms. Earned returns on equity have improved in recent years, too.

The dividend yield of Pinnacle West stock is about average for a utility. We project that, for at least the next few years, the company will maintain the 5% annual dividend growth rate that was established last fall. However, like several other electric utility equities, the recent price is above our 2017-2019 Target Price Range. Accordingly, total return potential is negative.

Paul E. Debbas, CFA *January 30, 2015*

(A) Diluted EPS. Excl. nonrec. losses: '02, 77¢; '09, $1.45; excl. gains (losses) from disc. ops.: '00, 22¢; '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). '11 EPS don't add due to rounding. Next earnings report due late Feb. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '13: $7.71/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '12: 10%; earned on avg. com. eq., '13: 9.9%. Regulatory Climate: Avg.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	65

PNM RESOURCES NYSE-PNM

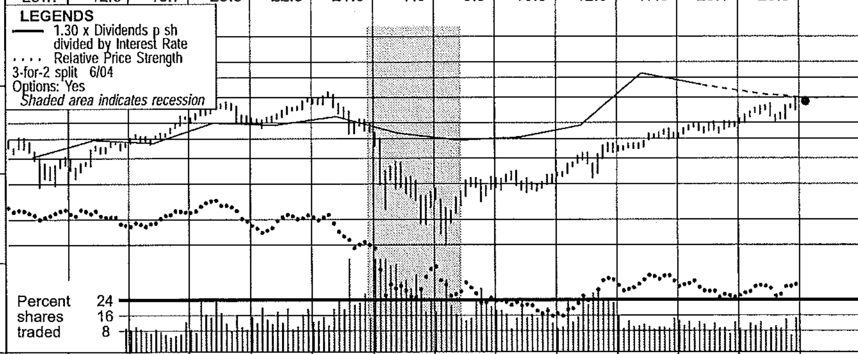
RECENT PRICE 30.59 | P/E RATIO 20.0 (Trailing: 21.0 Median: 16.0) | RELATIVE P/E RATIO 1.09 | DIV'D YLD 2.6% | VALUE LINE

TIMELINESS 2 Lowered 9/19/14
SAFETY 3 Lowered 5/9/08
TECHNICAL 3 Raised 12/5/14
BETA .85 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
High: 19.6	26.1	30.5	32.1	34.3	21.7	13.1	14.0	19.2	22.5	24.5	31.6
Low: 12.6	18.7	23.8	22.5	21.0	7.6	5.9	10.8	12.8	17.3	20.1	23.5

Target Price Range 2017 | 2018 | 2019

LEGENDS
—— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 6/04
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+30%)	9%
Low	30	(Nil)	3%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	10	0	0	0	0	0	0	0
to Sell	0	6	0	0	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	91	102	86
to Sell	101	90	101
Hld's(000)	69601	69780	71291

Percent shares traded 24 16 8

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	26.3	6.9
3 yr.	76.8	73.7
5 yr.	174.5	107.3

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
17.43	18.96	27.46	40.09	19.92	24.11	26.54	30.19	32.25	24.92	22.65	19.01	19.31	21.35	16.85	17.42	17.90	18.25	Revenues per sh	19.80
3.04	2.82	3.16	4.31	2.83	3.05	3.14	3.56	3.57	2.54	1.76	2.32	2.67	3.18	3.38	3.51	3.65	3.70	"Cash Flow" per sh	4.60
1.50	1.29	1.55	2.61	1.07	1.15	1.43	1.56	1.72	.76	.11	.58	.87	1.08	1.31	1.41	1.50	1.55	Earnings per sh A	2.35
.51	.53	.53	.53	.57	.61	.63	.79	.86	.91	.61	.50	.50	.50	.58	.68	.74	.80	Div'd Decl'd per sh B ■†	1.15
2.06	1.56	2.50	4.51	4.09	2.78	2.25	3.07	4.04	5.94	3.99	3.32	3.25	4.10	3.88	4.37	4.25	4.75	Cap'l Spending per sh	4.15
13.75	14.74	15.76	17.25	16.60	17.84	18.19	18.70	22.09	22.03	18.89	18.90	17.60	19.62	20.05	20.87	21.50	22.10	Book Value per sh C	24.50
62.66	61.05	58.68	58.68	58.68	60.39	60.46	68.79	76.65	76.81	86.53	86.67	86.67	79.65	79.65	79.65	80.00	80.00	Common Shs Outst'g D	80.00
9.8	9.5	8.5	7.3	15.1	14.7	15.0	17.4	15.6	35.6	NMF	18.1	14.0	14.5	15.0	16.1	18.1		Avg Ann'l P/E Ratio	15.0
.51	.54	.55	.37	.82	.84	.79	.93	.84	1.89	NMF	1.21	.89	.91	.95	.90	.94		Relative P/E Ratio	.95
3.5%	4.4%	4.1%	2.8%	3.5%	3.6%	2.9%	2.9%	3.2%	3.4%	4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	2.7%		Avg Ann'l Div'd Yield	3.3%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $1624.1 mill. Due in 5 Yrs $740.1 mill.
LT Debt $1542.1 mill. LT Interest $120 mill.
(LT interest earned: 2.4x)
Pension Assets-12/13 $556.4 mill.
Oblig. $599.5 mill.

Pfd Stock $11.5 mill. Pfd Div'd $.5 mill.
115,293 shs. 4.58%, $100 par w/o mandatory redemption. Sinking fund began 2/1/84.

Common Stock 79,653,624 shs.
as of 10/24/14
MARKET CAP: $2.4 billion (Mid Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
1604.8	2076.8	2471.7	1914.0	1959.5	1647.7	1673.5	1700.6	1342.4	1387.9	1430	1460	Revenues ($mill)	1585
88.3	106.6	122.1	59.9	8.1	53.5	80.0	96.6	105.6	113.5	120	125	Net Profit ($mill)	190
28.2%	31.1%	24.7%	5.1%	40.4%	30.4%	32.6%	38.8%	31.4%	31.6%	33.0%	35.0%	Income Tax Rate	35.0%
5.6%	15.6%	4.1%	--	--	6.4%	7.1%	8.8%	7.2%	1.3%	1.5%	2.5%	AFUDC % to Net Profit	8.0%
47.1%	57.4%	50.9%	42.0%	45.6%	48.7%	50.4%	51.5%	50.9%	50.0%	51.5%	52.0%	Long-Term Debt Ratio	53.5%
52.4%	42.3%	48.8%	57.6%	54.0%	51.0%	49.2%	48.1%	48.7%	49.7%	48.5%	48.0%	Common Equity Ratio	46.5%
2098.9	3044.4	3470.7	2935.8	3025.4	3214.9	3100.3	3245.6	3277.9	3344.0	3560	3695	Total Capital ($mill)	4195
2324.6	2984.1	3761.9	2935.4	3192.0	3332.4	3444.4	3627.1	3746.5	3933.9	4130	4335	Net Plant ($mill)	5020
5.3%	4.7%	4.9%	3.4%	1.9%	3.1%	4.2%	4.5%	5.1%	5.2%	5.0%	5.0%	Return on Total Cap'l	6.0%
7.9%	8.2%	7.2%	3.5%	.5%	3.2%	5.2%	6.1%	6.6%	6.8%	7.0%	7.0%	Return on Shr. Equity	9.5%
8.0%	8.2%	7.2%	3.5%	.5%	3.2%	5.2%	6.1%	6.6%	6.8%	7.0%	7.0%	Return on Com Equity E	9.5%
4.5%	4.3%	3.7%	NMF	NMF	.4%	2.2%	3.3%	3.8%	3.7%	3.5%	3.5%	Retained to Com Eq	5.0%
44%	48%	49%	117%	NMF	86%	58%	47%	43%	45%	50%	51%	All Div'ds to Net Prof	49%

ELECTRIC OPERATING STATISTICS F

	2011	2012	2013
% Change Retail Sales (KWH)	+3.4	-1.6	-2.9
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	N/A	N/A	N/A
Capacity at Peak (Mw)	2547	2537	2572
Peak Load, Summer (Mw)	1938	1948	2008
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+.4	+.4	+.7
Fixed Charge Cov. (%)	204	225	241

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-4.0%	-7.0%	1.0%
"Cash Flow"	--	5.0%	5.5%
Earnings	-2.5%	8.0%	11.0%
Dividends	0.5%	-6.0%	12.0%
Book Value	1.5%	-1.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	387.7	415.5	549.5	347.9	1700.6
2012	305.4	323.9	390.4	322.7	1342.4
2013	317.7	347.6	399.7	322.9	1387.9
2014	328.9	346.2	413.9	341	1430
2015	335	355	440	330	1460

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.04	.20	.61	.22	1.08
2012	.17	.33	.69	.13	1.31
2013	.18	.38	.64	.21	1.41
2014	.18	.39	.68	.25	1.50
2015	.25	.35	.70	.25	1.55

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.125	.125	.125	.125	.50
2012	.145	.145	.145	.145	.58
2013	.145	.165	.165	.165	.64
2014	.185	.185	.185	.185	.74
2015	.20				

BUSINESS: PNM Resources is an investor-owned holding company of energy and energy related businesses. Primary subsidiaries include Public Service Company of New Mexico (PNM) and Texas-New Mexico Power Company (TNMP), which generate, transmit, and distribute electricity in New Mexico and Texas. Sold First Choice Energy (9/11) and gas utility operations (1/09). Electric rev. breakdown '13: residential, 37%; commercial, 37%; industrial, 7%; other, 19%. Fuels: coal, 56.8%; nuclear, 30.4%; gas/oil, 12.2%; solar, .5%. Fuel costs: 49% of revs. '13 depr. rate: 3.0%. Has 1,924 employees. Chrmn., Pres. & CEO: Patricia K. Collawn. Inc.: NM. Address: 414 Silver Ave. SW, Albuquerque, NM. 87102. Tel.: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources has filed a general rate case in New Mexico for rates to be effective January 1, 2016. The rate request, which is based on a future test year of 2016, seeks a revenue increase of $107.4 million along with a ROE of 10.5%. PNM Resources is filing the increase to address the investments the company has made to reduce its reliance on coal and additional funds needed to maintain dependable service to its retail customers. It also seeks to highlight the declining sales growth within the company's service territory. The rate base of $2.4 billion includes the costs for 40 mw of solar facilities, the 40 mw natural gas-fired La Luz plant, emission-control technology at units 1 and 4 of the San Juan generating station, the purchase of the Rio Bravo generating station natural gas plant, and the purchase of Palo Verde Unit 2 leases. The company is also recommending changes to rate design to create fair distribution of costs. If approved, the rate increase is expected to affect customers by an average increase of 7.7% across rate classes.

The board of directors recently raised the dividend. The hike was $0.015 a share, bringing the annualized dividend to $0.80 an increase of approximately 8%. PNM is targeting a payout ratio of 50%-60% over the long term.

Our 2015 share-net call is at the midpoint of the company's guidance. We expect earnings to increase modestly in 2015. The company's Texas New Mexico Power Company continues to perform well, fueled by strong economic growth within its service territory. Sales advanced by 3.2%, driven by an increase in residential and commercial categories. Although load growth in the area has been of concern recently, results in New Mexico were better than expected as residential sales increased by 1.7%. Further, PNM Resources met a significant regulatory milestone earlier in October, with the approval of the revised state implementation plan for the San Juan generating station. The New Mexico Public Regulation Commission is expected to issue a final order in the first quarter of 2015.

This stock retains a favorable Timeliness rank (2). However, the current yield is below the utility average of 3.3%

Saumya Ajila *January 30, 2015*

(A) EPS dil. Excl. n/r gains (losses): '98, (24¢); '99, 8¢; '00, 21¢; '01, (15¢); '03, 67¢; '05, (56¢); '08, ($3.77); '10, ($1.36); '11, 88¢. '13,(16); Excl. disc. ops.: '08, 42¢; '09, 78¢. Egs. may not sum due to rounding. Next egs. rpt. due late Feb. (B) Div'ds hist. pd. in Feb., May, Aug., Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. '13: $3.49/sh. (D) In mill., adjust. for split. (E) Rate base: net orig. cost. ROE allowed in '11: 10.0%; earned on avg. com. eq., '13: 10.0%. Reg. Climate: Avg. (F) Excl. First Choice.

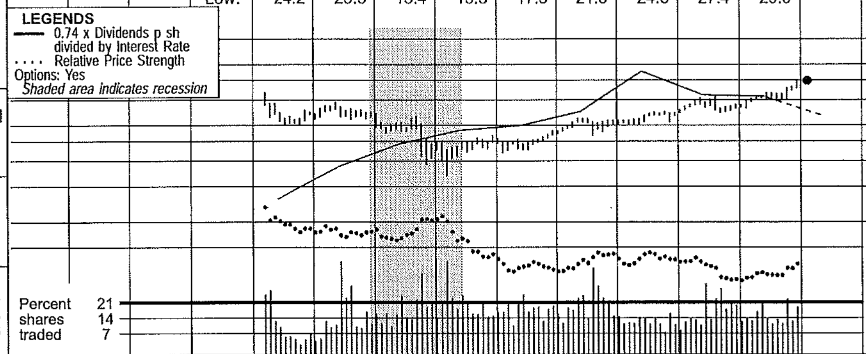
Company's Financial Strength	B
Stock's Price Stability	85
Price Growth Persistence	25
Earnings Predictability	25

PORTLAND GENERAL NYSE-POR

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
39.76	18.2	(Trailing: 17.9 Median: NMF)	0.99	2.9%	VALUE LINE

TIMELINESS 3 Lowered 12/5/14
SAFETY 2 Raised 5/4/12
TECHNICAL 3 Raised 1/9/15
BETA .80 (1.00 = Market)

High:	35.0	31.3	27.7	21.4	22.7	26.0	28.1	33.3	40.3			Target Price Range 2017 | 2018 | 2019
Low:	24.2	25.5	15.4	13.5	17.5	21.3	24.3	27.4	29.0			



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(-10%)	*Nil*
Low	25	(-35%)	*-7%*

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	1	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	121	127	123
to Sell	116	107	116
Hld's(000)	82774	82449	83632

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	29.4	6.9
3 yr.	65.6	73.7
5 yr.	122.5	107.3

On April 3, 2006, Portland General Electric's existing stock (which was owned by Enron) was canceled, and 62.5 million shares were issued to Enron's creditors or the Disputed Claims Reserve (DCR). The stock began trading on a when-issued basis that day, and regular trading began on April 10, 2006. Shares issued to the DCR were released over time to Enron's creditors until all of the remaining shares were released in June, 2007.

2004	2005G	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
--	23.14	24.32	27.87	27.89	23.99	23.67	24.06	23.89	23.18	*24.30*	*22.20*	Revenues per sh	*24.25*
--	4.75	4.64	5.21	4.71	4.07	4.82	4.96	5.15	4.93	*6.00*	*5.75*	"Cash Flow" per sh	*6.50*
--	1.02	1.14	2.33	1.39	1.31	1.66	1.95	1.87	1.77	*2.15*	*2.25*	Earnings per sh A	*2.50*
--	--	.68	.93	.97	1.01	1.04	1.06	1.08	1.10	1.12	*1.14*	Div'd Decl'd per sh B ■ †	*1.40*
--	4.08	5.94	7.28	6.12	9.25	5.97	3.98	4.01	8.40	*13.20*	*6.85*	Cap'l Spending per sh	*3.25*
--	19.15	19.58	21.05	21.64	20.50	21.14	22.07	22.87	23.30	*24.30*	*25.60*	Book Value per sh C	*29.00*
--	62.50	62.50	62.53	62.58	75.21	75.32	75.36	75.56	78.09	*78.25*	*89.00*	Common Shs Outst'g D	*89.75*
--	--	23.4	11.9	16.3	14.4	12.0	12.4	14.0	16.9	*15.5*		Avg Ann'l P/E Ratio	*12.5*
--	--	1.26	.63	.98	.96	.76	.78	.89	.95	*.80*		Relative P/E Ratio	*.80*
--	--	2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.4%		Avg Ann'l Div'd Yield	*4.4%*
1454.0	1446.0	1520.0	1743.0	1745.0	1804.0	1783.0	1813.0	1805.0	1810.0	*1900*	*1975*	Revenues ($mill)	*2175*
92.0	64.0	71.0	145.0	87.0	95.0	125.0	147.0	141.0	137.0	*170*	*195*	Net Profit ($mill)	*225*
37.0%	40.2%	33.6%	33.8%	28.7%	28.8%	30.5%	28.3%	31.4%	23.2%	*26.0%*	*24.0%*	Income Tax Rate	*24.0%*
9.8%	18.8%	33.8%	17.9%	17.2%	31.6%	17.6%	5.4%	7.1%	14.6%	*31.0%*	*12.0%*	AFUDC % to Net Profit	*4.0%*
41.1%	42.3%	43.4%	49.9%	46.2%	50.3%	53.0%	49.6%	47.1%	51.3%	*53.5%*	*45.0%*	Long-Term Debt Ratio	*45.5%*
58.9%	57.7%	56.6%	50.1%	53.8%	49.7%	47.0%	50.4%	52.9%	48.7%	*46.5%*	*55.0%*	Common Equity Ratio	*54.5%*
2171.0	2076.0	2161.0	2629.0	2518.0	3100.0	3390.0	3298.0	3264.0	3735.0	*4110*	*4140*	Total Capital ($mill)	*4775*
2275.0	2436.0	2718.0	3066.0	3301.0	3858.0	4133.0	4285.0	4392.0	4880.0	*5610*	*5900*	Net Plant ($mill)	*5875*
5.6%	4.6%	4.7%	6.9%	5.0%	4.5%	5.4%	6.2%	5.9%	5.1%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
7.2%	5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	*9.0%*	*8.5%*	Return on Shr. Equity	*9.0%*
7.2%	5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	*9.0%*	*8.5%*	Return on Com Equity E	*9.0%*
7.2%	5.3%	3.5%	6.6%	2.0%	1.5%	3.0%	4.1%	3.5%	2.9%	*4.5%*	*4.5%*	Retained to Com Eq	*4.0%*
--	--	39%	40%	69%	76%	62%	54%	57%	61%	*51%*	*49%*	All Div'ds to Net Prof	*55%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $2321 mill. **Due in 5 Yrs** $270 mill.
LT Debt $2251 mill. **LT Interest** $104 mill.
(LT interest earned: 2.8x)
Leases, Uncapitalized Annual rentals $11 mill.

Pension Assets-12/13 $596 mill. **Oblig.** $705 mill.

Pfd Stock None

Common Stock 78,209,672 shs. **as of 10/23/14**

MARKET CAP: $3.1 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+3.3	-.8	+1.2
Avg. Indust. Use (MWH)	16573	16409	16258
Avg. Indust. Revs. per KWH (¢)	5.44	5.26	4.84
Capacity at Peak (Mw)	4162	4173	4398
Peak Load, Winter (Mw) F	3555	3597	3869
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.2	+.7	+.9
Fixed Charge Cov. (%)	273	270	239

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	--	-2.5%	*.5%*
"Cash Flow"	--	.5%	*4.5%*
Earnings	--	3.0%	*5.0%*
Dividends	--	4.5%	*4.5%*
Book Value	--	2.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	484	411	439	479	1813
2012	479	413	450	463	1805
2013	473	403	435	499	1810
2014	493	423	484	*500*	*1900*
2015	*525*	*445*	*485*	*520*	*1975*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.92	.29	.36	.38	1.95
2012	.65	.34	.50	.38	1.87
2013	.65	.13	.40	.59	1.77
2014	.73	.43	.47	*.52*	*2.15*
2015	*.75*	*.45*	*.50*	*.55*	*2.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.26	.26	.265	.265	1.05
2012	.265	.265	.27	.27	1.07
2013	.27	.27	.275	.275	1.09
2014	.275	.275	.28	.28	1.11
2015	.28				

BUSINESS: Portland General Electric Company (PGE) provides electricity to 843,000 customers in 52 cities in a 4,000-square-mile area of Oregon, including Portland and Salem. The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 48%; commercial, 34%; industrial, 13%; other, 5%. Generating sources: coal, 19%; gas, 16%; hydro, 16%; wind, 6%; purchased, 43%. Fuel costs: 42% of revenues. '13 reported depreciation rate: 3.7%. Has 2,600 employees. Chairman: Jack E. Davis. President and Chief Executive Officer: James J. Piro. Incorporated: Oregon. Address: 121 SW Salmon Street, Portland, Oregon 97204. Telephone: 503-464-8000. Internet: www.portlandgeneral.com.

A rate increase for Portland General Electric Company took effect at the start of 2015. Tariffs were raised by $15 million (about 1%), based on a return of 9.68% on a common-equity ratio of 50%. The new allowed return on equity is slightly below the previous one of 9.75%. The rate order enabled PGE to place two projects, which began commercial operation in late 2014, in the rate base. A 267-megawatt wind farm was completed at a cost that was expected to be $500 million, and a 220-mw gas-fired peaking plant was built at a cost expected to be $296 million. The rate hike was small because cost reductions and customer credits offset most of what would have been a much larger increase.

Another generating plant is under construction. The 440-mw base-load gas-fired facility is expected to begin commercial operation in mid-2016 at a cost of $450 million. PGE will file a rate application next month in order to receive rate relief in 2016. Part of the increase will take effect at the start of the year, with the remainder coming when the new plant is completed.

Following what was almost certainly its much-improved earnings tally in 2014, we estimate earnings will climb at a mid-single-digit pace this year. Our 2014 estimate is at the midpoint of PGE's targeted range of $2.10-$2.20 a share. This year, the aforementioned rate order will help boost the company's profits. In addition, PGE's service territory is experiencing load growth, despite the effects of energy efficiency measures. The industrial sector is increasing its electricity usage. Our 2015 earnings estimate is $2.25 a share.

The share count will rise significantly this year. PGE expects to settle a forward equity sale for $278 million in the second quarter. The company intends to use the proceeds to pay down borrowings from its credit facilities.

This stock's dividend yield is somewhat below the industry average. The share price has already risen 5% this year. Like several other utility equities, the recent price is *above* our 2017-2019 Target Price Range. Thus, total return potential is negative.

Paul E. Debbas, CFA *January 30, 2015*

(A) Diluted EPS. Excl. nonrecurring loss: '13, 42¢. Next earnings report due mid-Feb. (B) Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '13: $5.94/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on com. eq. in '15: 9.68%; earned on avg. com. eq., '13: 7.6%. Regulatory Climate: Below Average. (F) Summer peak in '12. (G) '05 per-share data are pro forma, based on shares outstanding when stock began trading in '06.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	65

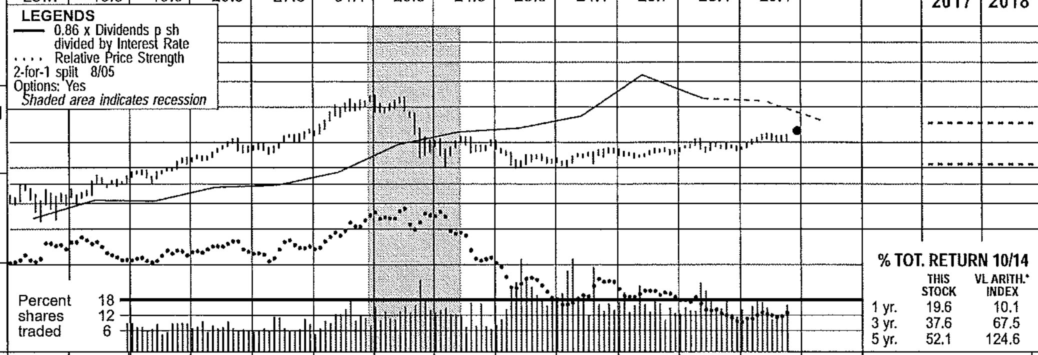
PPL CORPORATION NYSE-PPL

RECENT PRICE 36.57 | P/E RATIO 14.2 (Trailing: 18.1 Median: 14.0) | RELATIVE P/E RATIO 0.78 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Lowered 3/28/14
SAFETY 3 Lowered 11/28/08
TECHNICAL 3 Lowered 8/29/14
BETA .60 (1.00 = Market)

High:	22.2	27.1	33.7	37.3	54.6	55.2	34.4	33.1	30.3	30.2	33.6	36.8	
Low:	15.8	19.9	25.5	27.8	34.4	26.8	24.3	23.8	24.1	26.7	28.4	29.4	

Target Price Range 2017 | 2018 | 2019



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+10%)	6%
Low	25	(-30%)	-4%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	10	2	1	2	2	0	0	2
to Sell	0	6	2	3	2	4	0	0	1

Institutional Decisions

	4Q2013	1Q2014	2Q2014
to Buy	293	291	330
to Sell	252	277	238
Hld's(000)	419762	429819	460755

% TOT. RETURN 10/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	19.6	10.1
3 yr.	37.6	67.5
5 yr.	52.1	124.6

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
12.03	15.97	19.59	19.53	16.38	15.75	15.37	16.36	17.92	17.41	21.47	20.03	17.63	22.02	21.11	18.82	*15.65*	*18.80*	Revenues per sh	*20.50*
2.43	2.56	3.32	3.51	3.20	3.60	3.59	3.84	4.26	5.10	4.71	3.47	3.66	4.59	4.84	4.64	*4.30*	*4.70*	"Cash Flow" per sh	*5.25*
1.12	1.01	1.64	1.79	1.54	1.84	1.87	1.92	2.29	2.63	2.45	1.19	2.29	2.61	2.61	2.38	*2.10*	*2.35*	Earnings per sh A	*2.50*
.67	.50	.53	.53	.72	.77	.82	.96	1.10	1.22	1.34	1.38	1.40	1.40	1.44	1.47	*1.49*	*1.51*	Div'd Decl'd per sh B ■	*1.60*
.97	1.11	1.59	2.99	2.74	2.17	1.94	2.13	3.62	4.51	3.79	3.25	3.30	4.30	5.34	6.68	*6.25*	*5.65*	Cap'l Spending per sh	*5.50*
5.69	5.61	6.94	6.33	6.71	9.19	11.21	11.62	13.30	14.88	13.55	14.57	16.98	18.72	18.01	19.78	*20.65*	*21.50*	Book Value per sh C	*24.25*
314.82	287.39	290.08	293.16	331.47	354.72	378.14	380.15	385.04	373.27	374.58	377.18	483.39	578.41	581.94	630.32	*670.00*	*670.00*	Common Shs Outst'g D	*670.00*
10.9	13.4	8.9	12.4	11.1	10.6	12.5	15.1	14.1	17.3	17.6	25.7	11.9	10.5	10.9	12.8	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
.57	.76	.58	.64	.61	.60	.66	.80	.76	.92	1.06	1.71	.76	.66	.69	.72	*Value Line*		Relative P/E Ratio	*.85*
5.5%	3.7%	3.6%	2.4%	4.2%	4.0%	3.5%	3.3%	3.4%	2.7%	3.1%	4.5%	5.1%	5.1%	5.1%	4.8%	*estimates*		Avg Ann'l Div'd Yield	*4.8%*

CAPITAL STRUCTURE as of 6/30/14
Total Debt $21931 mill. **Due in 5 Yrs** $3998 mill.
LT Debt $20819 mill. **LT Interest** $946 mill.
Incl. 23 mill. units 7.75%, $25 liq. value; 82,000 units 8.23%, $1000 face value; 23 mill. units 4.625%, $50 stated value, conv. into com. in 2013.
(LT interest earned: 2.4x)
Leases, Uncapitalized Annual rentals $122 mill.
Pension Assets-12/13 $11440 mill.
Oblig. $12734 mill.
Pfd Stock None
Common Stock 664,381,143 shs.
as of 7/25/14
MARKET CAP: $24 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
5812.0	6219.0	6899.0	6498.0	8044.0	7556.0	8521.0	12737	12286	11860	*10500*	*12600*	Revenues ($mill)	*13750*
692.0	739.0	899.0	1031.0	940.0	465.0	1009.0	1456.0	1536.0	1541.0	*1405*	*1570*	Net Profit ($mill)	*1700*
22.8%	14.0%	23.2%	20.7%	31.8%	21.8%	22.0%	31.0%	26.2%	23.1%	*33.0%*	*26.0%*	Income Tax Rate	*26.0%*
.7%	--	--	--	.1%	9.5%	3.5%	4.0%	4.1%	3.7%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
61.6%	57.5%	55.4%	54.1%	57.1%	55.2%	59.0%	61.9%	64.1%	62.3%	*57.5%*	*57.0%*	Long-Term Debt Ratio	*57.5%*
37.9%	42.0%	42.2%	43.6%	40.5%	42.5%	39.8%	37.2%	35.9%	37.7%	*42.5%*	*43.0%*	Common Equity Ratio	*42.5%*
11171	10513	12151	12747	12529	12940	20621	29071	29205	33058	*32450*	*33500*	Total Capital ($mill)	*38000*
11209	10916	12069	12605	12416	13174	20858	27266	30032	33087	*35800*	*38025*	Net Plant ($mill)	*44600*
8.4%	9.3%	9.3%	9.8%	9.2%	5.2%	6.1%	6.5%	7.0%	6.2%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
16.1%	16.5%	16.6%	17.6%	17.5%	8.0%	11.9%	13.1%	14.7%	12.4%	*10.0%*	*11.0%*	Return on Shr. Equity	*10.5%*
16.3%	16.7%	17.3%	18.2%	18.2%	8.1%	12.0%	13.3%	14.6%	12.4%	*10.0%*	*11.0%*	Return on Com Equity E	*10.5%*
9.3%	8.8%	9.3%	10.0%	8.5%	NMF	5.2%	6.4%	6.7%	5.3%	*3.0%*	*4.0%*	Retained to Com Eq	*4.0%*
43%	47%	47%	46%	54%	115%	58%	52%	54%	57%	*69%*	*64%*	All Div'ds to Net Prof	*63%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+81.9	+14.6	+1.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	304	304	288

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	2.0%	2.0%	*Nil*
"Cash Flow"	3.0%	--	*2.0%*
Earnings	4.0%	.5%	*Nil*
Dividends	8.0%	3.5%	*2.0%*
Book Value	10.0%	6.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	2910	2489	3120	4218	12737
2012	4112	2549	2403	3222	12286
2013	2457	3450	3105	2848	11860
2014	1223	2874	3449	*2954*	*10500*
2015	*3350*	*3050*	*3150*	*3050*	*12600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.82	.35	.76	.69	2.61
2012	.93	.47	.61	.60	2.61
2013	.65	.63	.62	.46	2.32
2014	.49	.34	.73	*.54*	*2.10*
2015	*.80*	*.50*	*.55*	*.50*	*2.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.345	.35	.35	.35	1.40
2011	.35	.35	.35	.35	1.40
2012	.35	.36	.36	.36	1.43
2013	.36	.3675	.3675	.3675	1.46
2014	.3675	.3725	.3725	.3725	

BUSINESS: PPL Corporation (formerly PP&L Resources, Inc.) is a holding company for PPL Electric Utilities (formerly Pennsylvania Power & Light Company), which distributes electricity to 1.4 mill. customers in eastern & central PA. Acq'd Kentucky Utilities and Louisville Gas and Electric (1.2 mill. customers) 11/10. Has subs. in power generation & marketing, electricity distribution in U.K. (7.6 million customers). Sold gas distribution subsidiary in '08. The company no longer breaks out data on electric operating statistics. Fuel costs: 36% of revs. '13 reported deprec. rates: 2.6%-4.5%. Has 18,100 employees. Chairman, President & CEO: William H. Spence. Inc.: PA. Address: Two North Ninth St., Allentown, PA 18101-1179. Tel.: 800-345-3085. Internet: www.pplweb.com.

The spinoff of PPL's nonregulated energy-supply business is on track for completion in the first or second quarter of 2015. Low power prices and rising coal costs have squeezed this operation's margins in recent years. This is one of the main reasons why earnings declined in 2013, and are likely to do so again in 2014. The agreement calls for PPL to combine its merchant generating assets with those of another company, Riverstone, to form Talen Energy. PPL stockholders would get one share of Talen for each of their PPL shares in a tax-free transaction. The deal needs the approval of the Federal Energy Regulatory Commission, Pennsylvania Public Utility Commission, and Nuclear Regulatory Commission. Costs associated with the spinoff reduced earnings by $0.12 a share so far this year, and we *include* these expenses in our earnings presentation. Until the spinoff is completed, our estimates and projections will be based on PPL's current configuration. Note, too, that the board of directors won't review the dividend for a possible increase until after the move has been completed.

Once the spinoff has been effected, we expect steady annual earnings and dividend growth from PPL. The company will consist of regulated utilities in Pennsylvania (transmission and distribution only), Kentucky, and the United Kingdom.

The sale of PPL's hydro assets in Montana should close by yearend. The local utility is buying them for $895 million. PPL is now reporting these assets as discontinued operations.

The utilities in Kentucky will file rate cases at the end of this month. Kentucky Utilities expects to request an electric rate increase of $153 million (9.6%), based on a return of 10.5% on a common-equity ratio of 53.02%. Louisville Gas and Electric intends to seek electric and gas tariff hikes of $30 million (2.7%) and $14 million (4.4%), respectively, based on a return of 10.5% on a common-equity ratio of 52.75%. New rates should take effect at the start of July.

This stock offers a dividend yield that is somewhat above the utility average. Like most utility equities, 3- to 5-year total return potential is low.

Paul E. Debbas, CFA *November 21, 2014*

(A) Dil. EPS. Excl. nonrec. gain (losses): '07, (12¢); '10, (8¢); '11, 8¢; '13, (62¢); gains (losses) on disc. ops.: '05, (12¢); '07, 19¢; '08, 3¢; '09, (10¢); '10, (4¢); '12, (1¢); '14, 2¢. '11 EPS don't add due to rounding, '13 due to chg. in shs. Next egs. due early Feb. (B) Div'ds historically paid in early Jan., Apr., July, & Oct. ■ Div'd reinv. plan avail. (C) Incl. intang. In '13: $10.18/sh. (D) In mill., adj. for split. (E) Rate base: Fair val. Rate all'd on com. eq. in PA in '13: 10.4%; in KY in '13: 10.25%; earned on avg. com. eq., '13: 12.4%. Regul. Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	25
Earnings Predictability	60

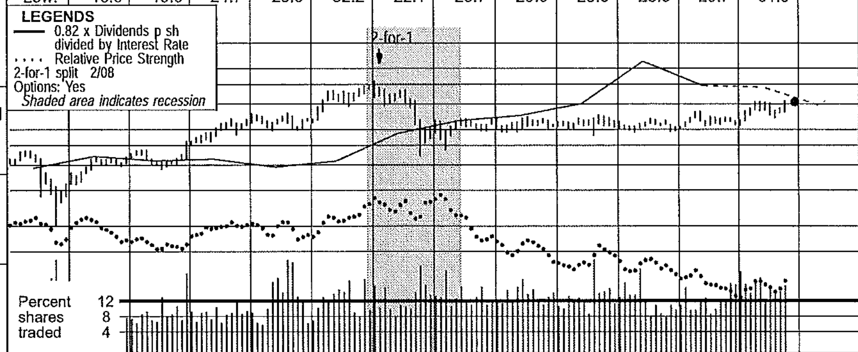
P.S. ENTERPRISE GP. NYSE-PEG

RECENT PRICE **40.95** | P/E RATIO **14.8** (Trailing: 16.8; Median: 14.0) | RELATIVE P/E RATIO **0.81** | DIV'D YLD **3.7%** | **VALUE LINE**

TIMELINESS 3 Lowered 9/19/14
SAFETY 1 Raised 11/23/12
TECHNICAL 5 Lowered 11/21/14
BETA .75 (1.00 = Market)

High:	22.3	26.3	34.2	36.3	49.9	52.3	34.1	34.9	35.5	34.1	37.0	42.1
Low:	16.0	19.0	24.7	29.5	32.2	22.1	23.7	29.0	28.0	28.9	29.7	31.3

LEGENDS
— 0.82 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 2/08
Options: Yes
Shaded area indicates recession



Target Price Range
2017 | 2018 | 2019

2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+10%)	6%
Low	35	(-15%)	Nil

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	1	0	0	0	0	0	0

Institutional Decisions

	4Q2013	1Q2014	2Q2014
to Buy	293	261	278
to Sell	214	261	235
Hld's(000)	330450	327280	329826

% TOT. RETURN 10/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	28.5	10.1
3 yr.	39.7	67.5
5 yr.	72.1	124.6

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
12.78	15.01	22.83	23.84	18.62	23.54	23.09	24.74	24.07	25.28	27.94	24.57	23.31	22.42	19.33	19.71	20.75	20.75	Revenues per sh	22.75
2.83	2.82	2.71	3.14	3.01	2.92	3.02	3.42	3.91	4.36	4.68	4.98	5.27	5.36	4.87	5.17	5.35	5.65	"Cash Flow" per sh	6.50
1.40	1.56	1.78	1.85	1.88	1.88	1.52	1.79	1.85	2.59	2.90	3.08	3.07	3.11	2.44	2.45	2.50	2.65	Earnings per sh A	3.00
1.08	1.08	1.08	1.08	1.08	1.08	1.10	1.12	1.14	1.17	1.29	1.33	1.37	1.37	1.42	1.44	1.48	1.52	Div'd Decl'd per sh B ■†	1.65
1.15	1.34	2.31	4.99	4.03	2.86	2.64	2.04	2.01	2.65	3.50	3.55	4.27	4.12	5.09	5.56	5.75	7.10	Cap'l Spending per sh	5.25
10.99	9.23	9.61	10.05	8.85	11.71	12.05	11.99	13.35	14.35	15.36	17.37	19.04	20.30	21.31	22.95	23.95	25.10	Book Value per sh C	29.00
463.92	432.83	415.94	411.68	450.53	472.27	476.20	502.33	505.29	508.52	506.02	505.99	505.97	505.95	505.89	505.86	506.00	506.00	Common Shs Outst'g D	506.00
12.7	12.5	10.3	12.0	10.0	10.6	14.3	16.5	17.8	16.5	13.6	10.0	10.4	10.4	12.8	13.5	*Bold figures are*		Avg Ann'l P/E Ratio	13.0
.66	.71	.67	.61	.55	.60	.76	.88	.96	.88	.82	.67	.66	.65	.81	.76	*Value Line*		Relative P/E Ratio	.80
6.1%	5.5%	5.9%	4.9%	5.7%	5.4%	5.1%	3.8%	3.5%	2.7%	3.3%	4.3%	4.3%	4.2%	4.6%	4.4%	*estimates*		Avg Ann'l Div'd Yield	4.2%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $8963 mill. **Due in 5 Yrs** $3380 mill.
LT Debt $8389 mill. **LT Interest** $372 mill.
Incl. $68 mill. securitized bonds.
(LT interest earned: 5.8x)

Leases, Uncapitalized Annual rentals $13 mill.
Pension Assets-12/13 $5116 mill.
Oblig. $4812 mill.
Pfd Stock None

Common Stock 505,959,967 shs.
as of 10/15/14
MARKET CAP: $21 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
10996	12430	12164	12853	14139	12431	11793	11343	9781.0	9968.0	10500	10500	Revenues ($mill)	11500
725.0	862.0	934.0	1323.0	1477.0	1567.0	1557.0	1577.0	1239.0	1243.0	1260	1355	Net Profit ($mill)	1550
38.1%	38.6%	36.6%	44.5%	45.9%	42.3%	40.5%	40.4%	36.2%	39.5%	40.0%	40.0%	Income Tax Rate	40.0%
15.9%	11.5%	4.7%	2.7%	3.2%	3.8%	5.5%	2.7%	4.8%	4.6%	5.0%	5.0%	AFUDC % to Net Profit	4.0%
69.0%	64.9%	60.3%	54.0%	50.5%	46.3%	44.8%	42.1%	38.3%	40.4%	41.0%	42.0%	Long-Term Debt Ratio	44.5%
30.6%	34.6%	39.2%	45.5%	49.0%	53.2%	55.2%	57.9%	61.7%	59.6%	59.0%	58.0%	Common Equity Ratio	55.5%
18744	17381	17197	16041	15856	16513	17452	17731	17467	19470	20575	21875	Total Capital ($mill)	26600
13750	13336	13002	13275	14433	15440	16390	17849	19736	21645	23175	25300	Net Plant ($mill)	29700
6.3%	7.3%	7.7%	10.4%	11.2%	11.0%	10.4%	10.2%	8.1%	7.5%	7.0%	7.0%	Return on Total Cap'l	7.0%
12.5%	14.1%	13.7%	17.9%	18.8%	17.7%	16.2%	15.4%	11.5%	10.7%	10.5%	10.5%	Return on Shr. Equity	10.5%
12.6%	14.2%	13.8%	18.1%	19.0%	17.8%	16.2%	15.4%	11.5%	10.7%	10.5%	10.5%	Return on Com Equity E	10.5%
3.5%	5.3%	5.3%	9.9%	10.5%	10.1%	9.0%	8.6%	4.8%	4.4%	4.0%	4.5%	Retained to Com Eq	5.0%
73%	63%	62%	45%	45%	43%	45%	44%	58%	59%	59%	57%	All Div'ds to Net Prof	54%

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-2.6	-2.1	-.9
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH(¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+.2	NA	NA
Fixed Charge Cov. (%)	580	504	529

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-.5%	-4.5%	2.0%
"Cash Flow"	5.5%	3.5%	4.0%
Earnings	3.5%	2.0%	2.0%
Dividends	2.5%	3.5%	2.5%
Book Value	7.5%	8.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	3354	2469	2884	2636	11343
2012	2875	2098	2402	2406	9781
2013	2786	2310	2554	2318	9968
2014	3223	2249	2641	2387	10500
2015	2950	2400	2700	2450	10500

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.91	.63	.86	.71	3.11
2012	.97	.42	.68	.37	2.44
2013	.63	.66	.77	.39	2.45
2014	.76	.42	.87	.45	2.50
2015	1.00	.45	.75	.45	2.65

Cal-endar	QUARTERLY DIVIDENDS PAID B ■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.343	.343	.343	.343	1.37
2011	.343	.343	.343	.343	1.37
2012	.355	.355	.355	.355	1.42
2013	.36	.36	.36	.36	1.44
2014	.37	.37	.37		

BUSINESS: Public Service Enterprise Group Incorporated is a holding company for Public Service Electric and Gas Company (PSE&G), which serves 2.2 million electric and 1.8 million gas customers in New Jersey, and PSEG Power LLC, a nonregulated power generator with nuclear, gas, and coal-fired plants in the Northeast. PSEG Energy Holdings is involved in renewable energy. The company no longer breaks out data on electric and gas operating statistics. Fuel costs: 35% of revenues. '13 reported depreciation rate (utility): 2.5%. Has 9,900 employees. Chairman, President & Chief Executive Officer: Dr. Ralph Izzo. Inc.: New Jersey. Address: 80 Park Plaza, P.O. Box 1171, Newark, New Jersey 07101-1171. Telephone: 973-430-7000. Internet: www.pseg.com.

Public Service Enterprise Group's utility subsidiary is benefiting from its investment in electric transmission. Public Service Electric and Gas expects to spend $6.8 billion on transmission from 2014 through 2018. The utility receives current cost recovery on this spending through a formula rate plan, and at an allowed return on equity that is more than one percentage point higher than its allowed ROE on distribution. In the first nine months of 2014, increased transmission income boosted the company's earnings by $0.10 a share. Under the formula rate plan, PSE&G has asked the Federal Energy Regulatory Commission for a $182 million rate increase, effective at the start of 2015.

There are other factors benefiting PSEG, too. PSE&G has investment opportunities beyond transmission — most notably, its $1.22 billion "Energy Strong" plan to enhance system reliability. (This arose from the effects of Hurricane Sandy in the fall of 2012.) The company is benefiting from its contract to run the electric utility on Long Island. Finally, lower pension expense is helping the bottom line.

We expect corporate profits to advance this year and next, despite margin pressure at PSEG Power. This nonutility subsidiary continues to face the effects of lower prices, so income here is headed down in 2014. We also include mark-to-market accounting losses, which were greater in the first nine months of 2014 than in the same period a year earlier. It appears that the worst is over, however. In addition, proposed changes to the wholesale markets in PSEG's region would benefit owners of generating assets. Note that PSEG Power will build a $600 million, 450-megawatt gas-fired plant in Connecticut if the company's bid into the market in 2015 is accepted.

High-quality PSEG stock has been one of the top-performing utility equities in 2014. Year to date, the price has risen 28%. The utility's prospects are good, and investors are also attracted to the prospects for a long-term recovery at PSEG Power. Following the stock's run-up, however, the dividend yield is only about average for a utility, and 3- to 5-year total return potential is negligible.

Paul E. Debbas, CFA *November 21, 2014*

(A) Dil. EPS. Excl. nonrecur. gain (losses): '99, ($1.75); '02, ($1.30); '05, (3¢); '06, (35¢); '08, (96¢); '09, 6¢; '11, (34¢); '12, 7¢; gains (loss) from disc. ops.: '05, (33¢); '06, 12¢; '07, 3¢; '08, 40¢; '11, 13¢. Next egs. report due late Feb. (B) Div'ds historically paid in late Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intang. In '13: $6.20/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '10: 10.3%; earned on avg. com. eq., '13: 11.2%. Reg. Climate: Avg.

Company's Financial Strength	A++
Stock's Price Stability	95
Price Growth Persistence	30
Earnings Predictability	85

SCANA CORP. NYSE-SCG

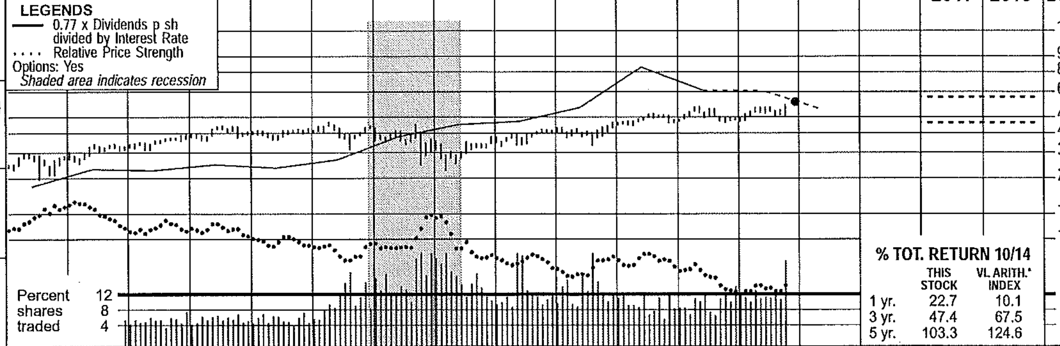
RECENT PRICE 57.01 | P/E RATIO 15.0 (Trailing: 15.0; Median: 14.0) | RELATIVE P/E RATIO 0.82 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS	3	Lowered 10/10/14
SAFETY	2	Lowered 9/10/99
TECHNICAL	4	Lowered 11/14/14

BETA .75 (1.00 = Market)

High:	35.7	39.7	43.7	42.4	45.5	44.1	38.6	42.0	45.5	50.3	54.4	57.1
Low:	28.1	32.8	36.6	36.9	32.9	27.8	26.0	34.2	34.6	43.3	44.7	45.6

LEGENDS
— 0.77 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2017 | 2018 | 2019

2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+5%)	5%
Low	45	(-20%)	-1%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	1	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	1	0	1	1	0	0	0

Institutional Decisions

	4Q2013	1Q2014	2Q2014
to Buy	168	194	192
to Sell	174	153	140
Hld's(000)	71165	72621	75177

Percent shares traded 12 / 8 / 4

% TOT. RETURN 10/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.7	10.1
3 yr.	47.4	67.5
5 yr.	103.3	124.6

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
15.76	15.93	32.78	32.95	26.65	30.85	34.53	41.66	39.11	39.61	45.16	34.35	36.10	33.95	31.63	31.88	34.25	32.90	Revenues per sh	36.00
3.62	3.15	4.43	4.55	4.56	4.95	5.28	7.43	5.68	5.73	5.86	5.63	5.91	6.01	6.30	6.53	7.15	7.20	"Cash Flow" per sh	8.00
2.12	1.44	2.12	2.15	2.38	2.50	2.67	2.78	2.59	2.74	2.95	2.85	2.98	2.97	3.15	3.39	3.80	3.90	Earnings per sh A	4.25
1.54	1.32	1.15	1.20	1.30	1.38	1.46	1.56	1.68	1.76	1.84	1.88	1.90	1.94	1.98	2.03	2.10	2.16	Div'd Decl'd per sh B ■	2.35
2.87	2.37	3.28	4.99	6.41	6.94	4.86	3.38	4.52	6.21	7.68	7.41	6.87	6.81	8.16	7.84	10.30	12.85	Cap'l Spending per sh	9.25
16.86	20.27	19.40	20.95	19.64	20.82	21.78	23.35	24.39	25.37	25.85	27.63	29.05	29.94	31.47	33.08	35.05	37.60	Book Value per sh C	43.75
103.57	103.57	104.73	104.73	110.83	110.74	112.52	114.67	116.67	116.67	117.78	123.34	127.45	129.88	132.01	141.00	143.00	149.00	Common Shs Outst'g D	157.00
14.5	17.5	12.5	12.6	12.2	13.0	13.6	14.4	15.4	15.0	12.7	11.6	12.9	13.7	14.8	14.4	Bold figures are		Avg Ann'l P/E Ratio	12.5
.75	1.00	.81	.65	.67	.74	.72	.77	.83	.80	.76	.77	.82	.86	.94	.81	Value Line		Relative P/E Ratio	.80
5.0%	5.2%	4.3%	4.4%	4.5%	4.2%	4.0%	3.9%	4.2%	4.3%	4.9%	5.7%	4.9%	4.8%	4.2%	4.2%	estimates		Avg Ann'l Div'd Yield	4.5%

CAPITAL STRUCTURE as of 6/30/14
Total Debt $6129 mill. Due in 5 Yrs $1478 mill.
LT Debt $5681 mill. LT Interest $297 mill.
(LT interest earned: 3.6x)

Leases, Uncapitalized Annual rentals $7 mill.
Pension Assets-12/13 $870.1 mill. Oblig. $823.0 mill.

Pfd Stock None

Common Stock 142,052,888 shs. as of 7/31/14

MARKET CAP: $8.1 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
3885.0	4777.0	4563.0	4621.0	5319.0	4237.0	4601.0	4409.0	4176.0	4495.0	4900	4900	Revenues ($mill)	5650
305.0	323.0	306.0	327.0	353.0	357.0	376.0	387.0	420.0	471.0	545	575	Net Profit ($mill)	685
32.5%	--	26.5%	29.2%	35.4%	32.0%	29.8%	30.3%	30.2%	32.1%	32.0%	31.0%	Income Tax Rate	32.0%
8.5%	.9%	2.6%	4.6%	8.5%	14.3%	8.0%	5.4%	7.6%	8.7%	9.0%	17.0%	AFUDC % to Net Profit	2.0%
55.4%	51.4%	50.9%	48.4%	58.0%	56.8%	52.9%	54.3%	54.4%	53.6%	54.5%	55.5%	Long-Term Debt Ratio	53.5%
42.6%	46.6%	47.2%	49.7%	40.5%	43.2%	47.1%	45.7%	45.6%	46.4%	45.5%	44.5%	Common Equity Ratio	46.5%
5752.0	5739.0	6027.0	5952.0	7519.0	7891.0	7854.0	8511.0	9103.0	10059	11000	12550	Total Capital ($mill)	14700
6762.0	6734.0	7007.0	7538.0	8305.0	9009.0	9662.0	10047	10896	11643	12650	14050	Net Plant ($mill)	16950
7.1%	7.4%	6.8%	7.3%	6.2%	6.1%	6.5%	6.2%	6.3%	6.1%	6.5%	6.0%	Return on Total Cap'l	6.0%
11.9%	11.6%	10.3%	10.6%	11.2%	10.5%	10.2%	10.0%	10.1%	10.1%	11.0%	10.5%	Return on Shr. Equity	10.0%
12.2%	11.8%	10.5%	10.8%	11.4%	10.2%	10.2%	10.0%	10.1%	10.1%	11.0%	10.5%	Return on Com Equity E	10.0%
5.6%	5.3%	3.8%	4.0%	4.4%	3.6%	3.8%	3.6%	3.9%	4.1%	5.0%	4.5%	Retained to Com Eq	4.5%
55%	56%	65%	64%	62%	66%	63%	64%	61%	60%	54%	55%	All Div'ds to Net Prof	54%

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-3.4	-3.9	+.3
Avg. Indust. Use (MWH)	8129	8055	8180
Avg. Indust. Revs. per KWH (¢)	6.87	7.09	7.27
Capacity at Yearend (Mw)	5642	5533	5237
Peak Load, Summer (Mw)	4885	4761	4574
Annual Load Factor (%)	57.3	56.8	58.8
% Change Customers (yr-end)	+.5	+.9	+1.2
Fixed Charge Cov. (%)	279	281	293

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	.5%	-4.5%	1.5%
"Cash Flow"	3.0%	2.0%	4.0%
Earnings	3.0%	3.0%	5.0%
Dividends	4.5%	2.5%	3.0%
Book Value	4.5%	4.5%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	1281	1000	1092	1036	4409.0
2012	1107	908	1038	1123	4176.0
2013	1311	1016	1051	1117	4495.0
2014	1590	1026	1121	1163	4900
2015	1500	1075	1125	1200	4900

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	1.00	.43	.81	.75	2.97
2012	.91	.54	.91	.78	3.15
2013	1.11	.60	.94	.73	3.39
2014	1.37	.68	1.01	.74	3.80
2015	1.35	.70	1.05	.80	3.90

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.47	.475	.475	.475	1.90
2011	.475	.485	.485	.485	1.93
2012	.485	.495	.495	.495	1.97
2013	.495	.5075	.5075	.5075	2.02
2014	.5075	.525	.525	.525	

BUSINESS: SCANA Corporation is a holding company for South Carolina Electric & Gas Company, which supplies electricity to 675,000 customers in South Carolina. Supplies gas and transmission service to 1.3 million customers in North and South Carolina and Georgia. Owns gas pipelines. Acquired PSNC Energy 2/00. Electric revenue breakdown: residential, 44%; commercial, 33%; industrial, 18%; other, 5%. Generating sources: coal, 48%; oil & gas, 28%; nuclear, 19%; hydro, 3%; purchased, 2%. Fuel costs: 51% of revenues. '13 reported deprec. rate: 2.9%. Has 6,000 employees. Chairman, CEO & President: Kevin B. Marsh. Incorporated: South Carolina. Address: 100 SCANA Parkway, Cayce, South Carolina 29033. Tel.: 803-217-9000. Internet: www.scana.com.

SCANA is still evaluating the cost of delays in its utility subsidiary's nuclear construction. The two units that South Carolina Electric & Gas is building at its Summer plant will add 1,340 megawatts of capacity. The contractors building the plant estimate that each unit will be delayed about a year—the first one until late 2018 or early 2019, the second 12 months later. The cost of SCE&G's share of the plant was $6.1 billion, but this will rise by more than 10%. However, the company has not yet accepted the revised schedule or costs, and is in talks with the contractors that management described as "fruitful to date." Once SCE&G has accepted a revised schedule and cost estimate, it will have to ask the South Carolina commission to update its previous order, which it issued based on a shorter construction schedule. Despite the cost increase, SCANA stock has fared well in 2014, having risen 18% year to date.

Earnings are likely to wind up significantly higher in 2014. Favorable weather patterns have added $0.23 a share to the company's profits this year. Accordingly, SCANA raised its share-earnings target from $3.45-$3.65 to $3.70-$3.90. Our estimate, which we raised by a nickel, is at the midpoint of the company's guidance. We look for a slight earnings increase in 2015, based on an increase in the Allowance for Funds Used During Construction, a noncash credit to income.

SCE&G received a rate hike under the state's Base Load Review Act. This act enables the utility to receive rate relief annually to place construction work in progress for the new nuclear units in the rate base. This year's increase was $66.2 million (2.8%). It took effect in late October. Note that SCE&G earns a return on equity of 11% on its new nuclear construction, which is very attractive.

We expect a dividend boost in the first quarter of 2015. Our estimate is for a $0.06-a-share (2.9%) raise in the annual disbursement.

The stock's dividend yield is just slightly above the industry average. With the recent price near the upper end of our 2017-2019 Target Price Range, total return potential over that time frame is low.

Paul E. Debbas, CFA *November 21, 2014*

(A) Dil egs. Excl. nonrec. gains (losses): '99, 29¢; '00, 28¢; '01, $3.00; '02, ($3.72); '03, 31¢; '04, (23¢); '05, 3¢; '06, 9¢. '11 EPS don't add due to change in shs., '12 & '13 due to rounding. Next earnings report due mid-Feb. (B) Div'ds historically paid in early Jan., Apr., July, and Oct. ■ Div'd reinv. plan avail. (C) Incl. intang. In '13: $9.65/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in SC: 10.25% elec. in '13, 10.25% gas in '05; in NC: 10.6% in '08; earned on avg. com. eq., '13: 10.7%. Regulatory Climate: Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	100

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Muldoon/39

SEMPRA ENERGY NYSE-SRE

RECENT PRICE 113.67 | P/E RATIO 24.3 (Trailing: 24.8; Median: 12.0) | RELATIVE P/E RATIO 1.32 | DIV'D YLD 2.4% | VALUE LINE

High:	30.9	37.9	47.9	57.3	66.4	63.0	57.2	57.2	56.0	72.9	93.0	116.3		Target Price Range
Low:	22.3	29.5	35.5	42.9	50.9	34.3	36.4	43.9	44.8	54.7	70.6	86.7		2017 | 2018 | 2019

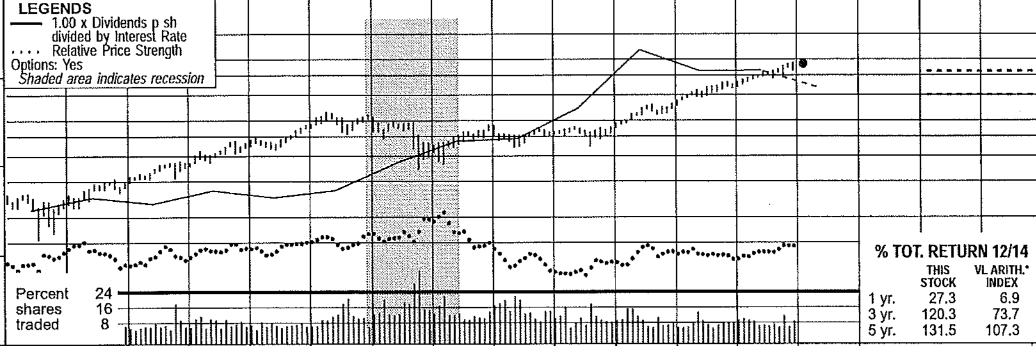
TIMELINESS 3 Raised 9/5/14

SAFETY 2 Lowered 2/4/00

TECHNICAL 3 Raised 12/19/14

BETA .75 (1.00 = Market)

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(-10%)	1%
Low	80	(-30%)	-5%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	1	0	0	0	0
Options	0	6	0	1	6	0	1	1	1
to Sell	0	3	0	2	6	0	1	1	1

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	234	232	239
to Sell	205	222	220
Hld's(000)	170920	172207	173962

Percent shares traded 24 16 8

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.3	6.9
3 yr.	120.3	73.7
5 yr.	131.5	107.3

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
23.31	22.89	35.38	39.27	29.38	34.81	40.18	45.64	44.89	43.79	44.21	32.88	37.44	41.83	39.80	43.18	*45.25*	*47.30*	Revenues per sh	*53.50*
5.16	5.36	4.91	5.39	5.71	5.56	6.58	5.96	6.74	6.93	7.40	7.94	7.76	8.58	8.92	8.87	*9.44*	*9.95*	"Cash Flow" per sh	*12.50*
1.24	1.66	2.06	2.55	2.79	3.01	3.93	3.52	4.23	4.26	4.43	4.78	4.02	4.47	4.35	4.22	*4.55*	*4.75*	Earnings per sh A	*6.25*
1.56	1.56	1.00	1.00	1.00	1.00	1.00	1.16	1.20	1.24	1.37	1.56	1.56	1.92	2.40	2.52	2.64	*2.76*	Div'd Decl'd per sh B ■	*3.20*
1.85	2.48	3.76	5.22	5.92	4.63	4.62	5.46	7.28	7.70	8.47	7.76	8.58	11.85	12.20	10.52	*13.00*	*12.15*	Cap'l Spending per sh	*12.00*
12.29	12.58	12.35	13.17	13.79	17.17	20.78	23.95	28.66	31.87	32.75	36.54	37.54	41.00	42.42	45.03	*46.80*	*48.70*	Book Value per sh C	*56.50*
237.00	237.40	201.90	204.48	204.91	226.60	234.18	257.19	262.01	261.21	243.32	246.51	240.45	239.93	242.37	244.46	*246.50*	*248.50*	Common Shs Outst'g D	*252.00*
21.1	12.8	9.4	9.7	8.2	9.0	8.6	11.8	11.5	14.0	11.8	10.1	12.6	11.8	14.9	19.7	*22.3*		Avg Ann'l P/E Ratio	*14.5*
1.10	.73	.61	.50	.45	.51	.45	.63	.62	.74	.71	.67	.80	.74	.95	1.11	*1.15*		Relative P/E Ratio	*.95*
6.0%	7.4%	5.2%	4.1%	4.4%	3.7%	2.9%	2.8%	2.5%	2.1%	2.6%	3.2%	3.1%	3.6%	3.7%	3.0%	2.6%		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $13934 mill. Due in 5 Yrs $5706 mill.
LT Debt $12437 mill. LT Interest $609 mill.
Incl. $236 mill. capitalized leases.
(LT interest earned: 3.7x)

Leases, Uncapitalized Annual rentals $85 mill.
Pension Assets-12/13 $2789 mill. Oblig. $3459 mill.
Pfd Stock $20 mill. Pfd Div'd $1.2 mill.
811,073 shs. 6% cum., $25 par.
Common Stock 246,218,250 shs.
as of 10/31/14
MARKET CAP: $28 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
9410.0	11737	11761	11438	10758	8106.0	9003.0	10036	9647.0	10557	*11150*	*11750*	Revenues ($mill)	*13500*
930.0	898.0	1118.0	1135.0	1123.0	1193.0	1008.0	1088.0	1079.0	1060.0	*1245*	*1305*	Net Profit ($mill)	*1725*
17.2%	--	31.3%	33.6%	29.2%	30.5%	26.5%	25.3%	18.2%	26.5%	*28.0%*	*32.0%*	Income Tax Rate	*31.0%*
2.9%	5.3%	7.2%	11.5%	13.2%	10.6%	11.3%	15.2%	17.2%	11.2%	*12.0%*	*12.0%*	AFUDC % to Net Profit	*9.0%*
45.3%	43.1%	37.0%	34.8%	44.5%	44.8%	49.4%	50.4%	52.8%	50.5%	*51.0%*	*51.0%*	Long-Term Debt Ratio	*51.5%*
52.6%	55.1%	61.4%	63.7%	54.2%	54.1%	49.6%	49.2%	46.7%	49.4%	*49.0%*	*48.5%*	Common Equity Ratio	*48.5%*
9255.0	11178	12229	13071	14692	16646	18186	20015	22002	22281	*23525*	*24825*	Total Capital ($mill)	*29500*
11086	12101	13175	14884	16865	18281	19876	23572	25191	25460	*27475*	*29225*	Net Plant ($mill)	*33400*
11.3%	9.2%	10.3%	9.6%	8.5%	8.3%	6.8%	6.7%	6.1%	6.0%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
18.4%	14.1%	14.5%	13.3%	13.8%	13.0%	10.9%	10.9%	10.4%	9.6%	*10.0%*	*10.0%*	Return on Shr. Equity	*11.5%*
18.9%	14.4%	14.8%	13.5%	14.0%	13.1%	11.1%	11.0%	10.4%	9.6%	*10.0%*	*10.0%*	Return on Com Equity E	*11.5%*
14.9%	10.1%	11.0%	9.7%	9.7%	9.3%	7.0%	6.5%	5.1%	4.1%	*4.5%*	*4.5%*	Retained to Com Eq	*5.5%*
22%	31%	26%	29%	31%	29%	37%	41%	52%	58%	*57%*	*57%*	All Div'ds to Net Prof	*50%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+.1	+2.6	-1.3
Avg. Indust. Use (MWH)	4157	4335	4279
Avg. Indust. Revs. per KWH (¢)	12.13	12.19	13.10
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.6	+.5	+.5
Fixed Charge Cov. (%)	319	262	307

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	2.0%	-1.0%	*4.5%*
"Cash Flow"	4.5%	4.5%	*6.0%*
Earnings	4.5%	--	*6.0%*
Dividends	8.5%	12.5%	*6.0%*
Book Value	11.5%	6.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	2434	2422	2576	2604	10036
2012	2383	2089	2507	2668	9647
2013	2650	2651	2551	2705	10557
2014	2795	2678	2815	*2862*	*11150*
2015	*2950*	*2850*	*2950*	*3000*	*11750*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	1.07	.97	1.22	1.21	4.47
2012	.97	.98	1.33	1.08	4.35
2013	.54	1.46	1.09	1.13	4.22
2014	.99	1.08	1.39	*1.09*	*4.55*
2015	*1.05*	*1.15*	*1.40*	*1.15*	*4.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.39	.48	.48	.48	1.83
2012	.48	.60	.60	.60	2.28
2013	.60	.63	.63	.63	2.49
2014	.63	.66	.66	.66	2.61
2015	.66				

BUSINESS: Sempra Energy is a holding co. for San Diego Gas & Electric Company, which sells electricity & gas mainly in San Diego County, & Southern California Gas Company, which distributes gas to most of Southern California. Customers: 1.4 mill. electric, 6.6 mill. gas. Elec. rev. breakdown: residential, 46%; commercial, 38%; industrial, 9%; other, 7%. Purchases most of its power; the rest is gas. Has subs. in gas pipeline & storage, power generation, & liquefied natural gas. Sold commodities business in '10. Power costs: 38% of revs. '13 reported deprec. rates: 1.6%-7.6%. Has 17,100 employees. Chairman and CEO: Debra L. Reed. President: Mark A. Snell. Inc.: CA. Address: 101 Ash St., San Diego, CA 92101-3017. Tel.: 619-696-2034. Internet: www.sempra.com.

Sempra Energy has begun construction of a large project. The company is converting its Cameron liquefied natural gas terminal from an import to an export facility. Sempra has a 50.2% stake in the project, which is expected to cost $9 billion-$10 billion. It is expected to be completed in 2018 and should provide Sempra with net profit of $325 million-$350 million annually. The project might be expanded, too; the company will file a request with the Federal Energy Regulatory Commission this year.

Sempra's utilities have filed general rate cases. Southern California Gas requested a $256 million increase, and San Diego Gas & Electric asked for a total (electric and gas) hike of $133 million. An order from the California regulators is expected by yearend, but even if it slips into 2016, it will be retroactive to the start of next year.

Earnings should improve in 2015. International investments are a particular area of focus for Sempra. The company has a lot of projects in various stages of development in Latin America and South America, especially natural gas pipelines in Mexico.

An asset sale is expected to close soon. Sempra has agreed to sell its 50% stake in a nonregulated gas-fired power plant. The company expects to book an undisclosed gain on the sale, which we will exclude from our earnings presentation as a nonrecurring item.

A new corporate structure might be in Sempra's future. The company is evaluating changes such as the formation of a "yieldco" that NRG Energy formed in 2013 or a master limited partnership and NextEra Energy formed in 2014. Sempra expects to make an announcement around the end of the current quarter. Our estimates and projections are based on the company's current configuration.

This stock is expensively priced. Like several other utility equities, it is trading *above* our 2017-2019 Target Price Range. Perhaps Wall Street is anticipating some kind of corporate structure move. The stock doesn't stand out among utilities for its dividend yield, even though we estimate a sizable increase in the payout in the current quarter.

Paul E. Debbas, CFA *January 30, 2015*

(A) Dil. EPS. Excl. nonrec. gains (losses): '05, 17¢; '06, (6¢); '09, (26¢); '10, ($1.05); '11, $1.15; '12, (98¢); '13, (30¢) net; gain (losses) from disc. ops.: '04, (10¢); '05, (4¢); '06, $1.21; '07, (10¢). '12 EPS don't add due to rounding. Next egs. report due late Feb. (B) Div'ds histor. paid mid-Jan., Apr., July & Oct. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '13: $16.35/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq.: SDG&E in '13: 10.3%; SoCalGas in '13: 10.1%; earn. on avg. com. eq., '13: 9.6%. Reg. Climate: Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	95

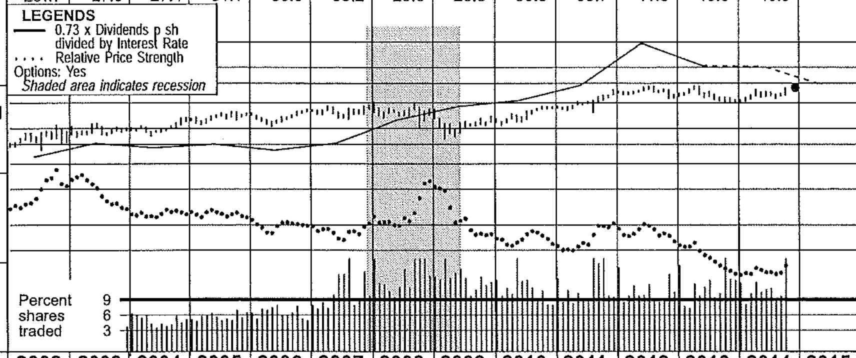
SOUTHERN COMPANY NYSE-SO

RECENT PRICE 47.58 | P/E RATIO 17.6 (Trailing: 16.3 / Median: 16.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 4.5% | VALUE LINE

TIMELINESS 3 Lowered 3/21/14
SAFETY 2 Lowered 2/21/14
TECHNICAL 4 Lowered 11/14/14
BETA .55 (1.00 = Market)

High:	32.0	34.0	36.5	37.4	39.3	40.6	37.6	38.6	46.7	48.6	48.7	48.0
Low:	27.0	27.4	31.1	30.5	33.2	29.8	26.5	30.8	35.7	41.8	40.0	40.3

LEGENDS
— 0.73 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2017 | 2018 | 2019

2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+5%)	6%
Low	40	(-15%)	1%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	1	0	0	0
Options	1	0	0	0	1	2	0	2	1
to Sell	1	0	0	0	1	2	0	2	1

Institutional Decisions

	4Q2013	1Q2014	2Q2014
to Buy	419	423	485
to Sell	412	377	342
Hld's(000)	423718	435514	446155

Percent shares traded 9 6 3

% TOT. RETURN 10/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	18.8	10.1
3 yr.	24.2	67.5
5 yr.	87.6	124.6

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
16.34	17.40	14.78	14.54	14.73	15.31	16.05	18.28	19.24	20.12	22.04	19.21	20.70	20.41	19.06	19.26	*20.60*	*20.70*	Revenues per sh	*22.50*
4.26	4.17	3.89	3.55	3.46	3.53	3.65	4.03	4.01	4.22	4.43	4.43	4.51	4.91	5.18	5.27	*5.50*	*5.75*	"Cash Flow" per sh	*6.50*
1.73	1.83	2.01	1.61	1.85	1.97	2.06	2.13	2.10	2.28	2.25	2.32	2.36	2.55	2.67	2.70	*2.80*	*2.90*	Earnings per sh A	*3.25*
1.34	1.34	1.34	1.34	1.36	1.39	1.42	1.48	1.54	1.60	1.66	1.73	1.80	1.87	1.94	2.01	*2.08*	*2.15*	Div'd Decl'd per sh B ■ †	*2.36*
2.87	3.85	3.27	3.75	3.79	2.72	2.85	3.20	4.01	4.65	5.10	5.70	4.85	5.23	5.54	6.16	*8.00*	*6.40*	Cap'l Spending per sh	*6.50*
14.04	13.82	15.69	11.43	12.16	13.13	13.86	14.42	15.24	16.23	17.08	18.15	19.21	20.32	21.09	21.43	*21.95*	*22.65*	Book Value per sh C	*26.00*
697.75	665.80	681.16	698.34	716.40	734.83	741.50	741.45	746.27	763.10	777.19	819.65	843.34	865.13	867.77	887.09	*902.00*	*904.00*	Common Shs Outst'g D	*940.00*
15.7	14.3	13.2	14.6	14.6	14.8	14.7	15.9	16.2	16.0	16.1	13.5	14.9	15.8	17.0	16.2	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.82	.82	.86	.75	.80	.84	.78	.85	.87	.85	.97	.90	.95	.99	1.08	.91	*Value Line*		Relative P/E Ratio	*.90*
4.9%	5.1%	5.0%	5.7%	5.0%	4.7%	4.7%	4.4%	4.5%	4.4%	4.6%	5.5%	5.1%	4.6%	4.3%	4.6%	*estimates*		Avg Ann'l Div'd Yield	*5.2%*

CAPITAL STRUCTURE as of 6/30/14
Total Debt $24523 mill. **Due in 5 Yrs** $9106 mill.
LT Debt $22121 mill. **LT Interest** $816 mill.
(LT interest earned: 5.6x)
Leases, Uncapitalized Annual rentals $101 mill.
Pension Assets-12/13 $8733 mill. **Obl.** $8863 mill.
Pfd Stock $1131 mill. **Pfd Div'd** $68 mill.
Incl. 1 mill. shs. 4.2%-5.44% cum. pfd. ($100 par); 12 mill. shs. 5.2%-5.83% cum. pfd. ($1 par); 2 mill. shs. 6.0% noncum. pfd. ($25 par); 4 mill. shs. 5.6%-6.5% noncum. pfd. ($100 par); 14 mill. shs. 5.63%-6.5% noncum. pfd. ($1 par).
Common Stock 895,696,608 shs.
MARKET CAP: $43 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
11902	13554	14356	15353	17127	15743	17456	17657	16537	17087	*18600*	*18700*	Revenues ($mill)	*21250*
1589.0	1621.0	1608.0	1782.0	1807.0	1910.0	2040.0	2268.0	2415.0	2439.0	*2600*	*2700*	Net Profit ($mill)	*3145*
27.0%	26.9%	32.7%	31.9%	33.6%	31.9%	33.5%	35.0%	35.6%	34.8%	*35.5%*	*35.5%*	Income Tax Rate	*35.5%*
5.2%	4.4%	4.8%	9.5%	12.3%	14.9%	13.7%	10.2%	9.4%	11.6%	*13.0%*	*12.0%*	AFUDC % to Net Profit	*12.0%*
53.5%	53.2%	50.8%	51.2%	53.9%	53.2%	51.2%	50.0%	49.9%	51.5%	*53.0%*	*55.5%*	Long-Term Debt Ratio	*56.5%*
44.1%	44.3%	46.2%	44.9%	42.6%	43.6%	45.7%	47.1%	47.3%	45.8%	*44.5%*	*42.5%*	Common Equity Ratio	*41.5%*
23288	24131	24618	27608	31174	34091	35438	37307	38653	41483	*44450*	*48275*	Total Capital ($mill)	*58600*
28361	29480	31092	33327	35878	39230	42002	45010	48390	51208	*55975*	*59225*	Net Plant ($mill)	*67600*
8.1%	8.2%	8.2%	7.9%	7.1%	6.9%	7.0%	7.2%	7.3%	6.8%	*7.0%*	*6.5%*	Return on Total Cap'l	*6.5%*
14.7%	14.4%	13.3%	13.2%	12.6%	12.0%	11.8%	12.2%	12.5%	12.1%	*12.5%*	*12.5%*	Return on Shr. Equity	*12.5%*
14.9%	14.9%	13.8%	14.0%	13.1%	12.4%	12.2%	12.5%	12.8%	12.5%	*13.0%*	*13.0%*	Return on Com Equity E	*12.5%*
4.7%	4.6%	3.8%	4.3%	3.5%	3.2%	3.0%	3.4%	3.6%	3.2%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
69%	70%	73%	70%	74%	75%	77%	73%	73%	75%	*74%*	*74%*	All Div'ds to Net Prof	*72%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-2.7	-2.3	+.3
Avg. Indust. Use (MWH)	3438	3445	3495
Avg. Indust. Revs. per KWH (¢)	6.37	5.94	6.08
Capacity at Yearend (Mw)	43555	45750	45502
Peak Load, Summer (Mw)	36956	35479	33557
Annual Load Factor (%)	59.0	59.5	63.2
% Change Customers (yr-end)	-.1	+.5	+.7
Fixed Charge Cov. (%)	397	416	423

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	3.0%	-1.0%	2.5%
"Cash Flow"	4.0%	4.0%	4.0%
Earnings	4.0%	3.5%	3.5%
Dividends	3.5%	4.0%	3.5%
Book Value	5.5%	5.5%	3.5%

Cal-endar	QUARTERLY REVENUES (mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	4012	4521	5428	3696	17657
2012	3604	4181	5049	3703	16537
2013	3897	4246	5017	3927	17087
2014	4644	4467	5339	*4150*	*18600*
2015	*4250*	*4650*	*5550*	*4250*	*18700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.49	.70	1.06	.30	2.55
2012	.42	.71	1.11	.43	2.67
2013	.47	.66	1.08	.49	2.70
2014	.66	.68	1.09	*.37*	*2.80*
2015	*.50*	*.75*	*1.20*	*.45*	*2.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.4375	.455	.455	.455	1.80
2011	.455	.4725	.4725	.4725	1.87
2012	.4725	.49	.49	.49	1.94
2013	.49	.5075	.5075	.5075	2.01
2014	.5075	.525	.525		

BUSINESS: The Southern Company, through its subsidiaries, supplies electricity to 4.5 million customers in about 120,000 square miles of Georgia, Alabama, Florida, and Mississippi. Also has competitive generation business. Electric revenue breakdown: residential, 37%; commercial, 32%; industrial, 19%; other, 12%. Retail revenues by state: Georgia, 50%; Alabama, 34%; Florida, 9%; Mississippi, 7%. Generating sources: oil & gas, 37%; coal, 37%; nuclear, 16%; hydro, 4%; purchased, 6%. Fuel costs: 35% of revenues. '13 reported deprec. rate (utility): 3.3%. Has 26,300 employees. Chairman, President and CEO: Thomas A. Fanning. Inc.: Delaware. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, Georgia 30308. Tel.: 404-506-5000. Internet: www.southerncompany.com.

The coal gasification plant being built by Southern Company's Mississippi Power unit continues to have delays. The facility is generating power from natural gas, but the gasifier has been delayed. The 495-megawatt project was originally expected to be completed in May of 2014, but the revised target is the first half of 2016. The overruns above a cost cap of $2.88 billion are not recoverable in rates, so the company took a nonrecurring charge of $258 million after taxes ($0.29 a share) in the September quarter, after having taken a writedown in the first period. So far, aftertax charges in 2013 and 2014 have totaled more than $1.2 billion.

The company's Georgia Power subsidiary is building two nuclear units. This would provide the utility with 1,005 mw of capacity at a projected cost of $6.8 billion. The project has been delayed a year, to the fourth quarters of 2017 and 2018. There is an ongoing dispute with contractors about which party is responsible for the additional costs stemming from the delay, but the problems haven't been nearly as severe as for the coal gasification plant. The revised in-service dates are still achievable, but management concedes that there is "ongoing pressure on this construction schedule."

We estimate that earnings will rise moderately in 2014 and 2015. Southern Company is benefiting from rate relief at Georgia Power and Gulf Power. Weather patterns were favorable in the first quarter of this year. Our 2014 estimate is at the upper end of management's guidance of $2.72-$2.80 a share. We forecast that profits will rise to $2.90 a share in 2015, in line with its 3%-4% growth target.

Southern Company stock has a dividend yield that is a percentage point above the utility mean. The ongoing delays about the coal gasification plant have hurt the stock: It was one of the worst-performing utility issues in 2013. Although construction of the nuclear units has not been as problematic, so far, there is also some worry here. Although Southern Company offers decent dividend growth potential, 3- to 5-year total returns will likely be unspectacular because the recent price is above the midpoint of our 2017-2019 Target Price Range.

Paul E. Debbas, CFA *November 21, 2014*

(A) Diluted earnings. Excl. nonrecurring gain (losses): '03, 6¢; '09, (25¢); '13, (83¢); '14, (55¢). Next earnings report due early Feb. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. deferred charges. In '13: $5.59/sh. (D) In mill. (E) Rate base: AL, MS, fair value; FL, GA, orig. cost. Allowed return on com. eq. (blended): 12.5%; earned on avg. com. eq., '13: 12.5%. Regulatory Climate: GA, AL Above Average; MS, FL Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	100

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TECO ENERGY, INC. NYSE-TE

RECENT PRICE 19.62 | P/E RATIO 18.5 (Trailing: 19.4 Median: 15.0) | RELATIVE P/E RATIO 1.02 | DIV'D YLD 4.5% | VALUE LINE

TIMELINESS	3	Lowered 10/3/14
SAFETY	2	Raised 2/24/12
TECHNICAL	4	Lowered 11/14/14

BETA .85 (1.00 = Market)

High:	17.0	15.5	19.3	17.7	18.6	22.0	16.7	18.1	19.7	19.4	19.2	20.2		
Low:	9.5	11.3	14.9	14.4	14.8	10.5	8.4	14.5	15.8	16.1	16.2	16.1		

Target Price Range 2017 | 2018 | 2019

2017-19 PROJECTIONS

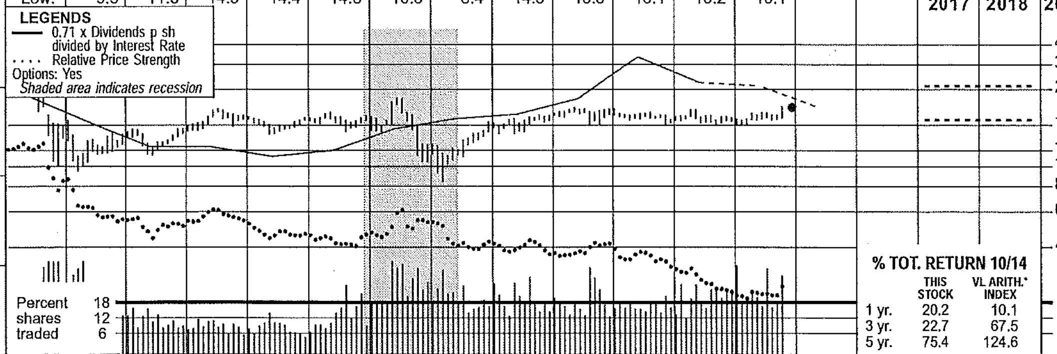
	Price	Gain	Ann'l Total Return
High	25	(+25%)	*10%*
Low	17	(-15%)	*1%*

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	1	0	1	0	0	1	0
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2013	1Q2014	2Q2014
to Buy	145	166	155
to Sell	154	140	144
Hld's(000)	133931	130939	134541



% TOT. RETURN 10/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.2	10.1
3 yr.	22.7	67.5
5 yr.	75.4	124.6

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
14.83	15.01	18.17	18.97	15.22	14.59	13.37	14.46	16.46	16.77	15.85	15.48	16.23	15.49	13.83	13.12	*10.85*	*12.15*	Revenues per sh	*14.25*
3.25	3.28	4.11	4.31	3.20	1.96	2.14	2.37	2.51	2.51	2.01	2.35	2.59	2.77	2.69	2.43	*2.30*	*2.55*	"Cash Flow" per sh	*3.25*
1.52	1.53	1.97	2.24	1.95	d.08	.71	1.00	1.17	1.27	.77	1.00	1.13	1.27	1.14	.92	*1.00*	*1.10*	Earnings per sh [A]	*1.40*
1.23	1.29	1.33	1.37	1.41	.93	.76	.76	.76	.78	.80	.80	.82	.85	.88	.88	*.88*	*.88*	Div'd Decl'd per sh [B] ■	*1.00*
2.24	3.23	5.45	6.92	6.06	3.14	1.37	1.42	2.18	2.34	2.77	2.99	2.28	2.10	2.33	2.45	*3.15*	*3.00*	Cap'l Spending per sh	*2.00*
11.42	10.73	11.93	14.12	14.86	8.93	6.43	7.65	8.25	9.56	9.43	9.75	10.10	10.50	10.58	10.74	*10.95*	*11.10*	Book Value per sh [C]	*12.00*
132.00	132.10	126.30	139.60	175.80	187.80	199.70	208.20	209.50	210.90	212.90	213.90	214.90	215.80	216.60	217.30	*234.60*	*234.60*	Common Shs Outst'g [D]	*234.60*
17.8	14.2	11.9	12.9	11.0	--	19.3	17.1	13.8	13.3	21.2	12.6	14.6	14.4	15.5	18.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.93	.81	.77	.66	.60	--	1.02	.91	.75	.71	1.28	.84	.93	.90	.99	1.06	*Value Line*		Relative P/E Ratio	*.90*
4.5%	5.9%	5.7%	4.8%	6.6%	7.4%	5.5%	4.4%	4.7%	4.6%	4.9%	6.3%	4.9%	4.6%	5.0%	5.1%	*estimates*		Avg Ann'l Div'd Yield	*5.0%*

CAPITAL STRUCTURE as of 6/30/14
Total Debt $3137.6 mill. Due in 5 Yrs $1295.4 mill.
LT Debt $2863.1 mill. LT Interest $150.7 mill.
(LT interest earned: 3.0x)

Leases, Uncapitalized Annual rentals $5.0 mill.

Pension Assets-12/13 $593.0 mill. **Oblig.** $666.0 mill.

Pfd Stock None

Common Stock 233,407,893 shs.
as of 7/28/14
MARKET CAP: $4.6 billion (Mid Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
2669.1	3010.1	3448.1	3536.1	3375.3	3310.5	3487.9	3343.4	2996.6	2851.3	*2550*	*2850*	Revenues ($mill)	*3350*
137.4	211.0	244.4	265.8	162.4	213.9	242.9	272.6	246.0	197.8	*220*	*255*	Net Profit ($mill)	*320*
38.5%	45.1%	40.4%	40.7%	36.8%	31.6%	34.8%	36.1%	35.9%	35.5%	*35.5%*	*35.5%*	Income Tax Rate	*35.5%*
.7%	.0%	1.6%	2.3%	5.4%	6.5%	1.2%	.6%	1.7%	5.0%	*7.0%*	*6.0%*	AFUDC % to Net Profit	*2.0%*
75.1%	70.0%	65.0%	61.0%	61.5%	60.6%	59.2%	54.2%	56.5%	54.9%	*56.0%*	*57.5%*	Long-Term Debt Ratio	*57.5%*
24.9%	30.0%	35.0%	39.0%	38.5%	39.4%	40.8%	45.8%	43.5%	45.1%	*44.0%*	*42.5%*	Common Equity Ratio	*42.5%*
5163.9	5300.9	4941.6	5175.4	5214.3	5287.0	5317.8	4953.9	5264.5	5171.5	*5865*	*6105*	Total Capital ($mill)	*6600*
4657.9	4566.9	4766.9	4888.2	5221.3	5544.1	5841.0	5967.8	5990.1	6170.1	*6955*	*7305*	Net Plant ($mill)	*7600*
5.6%	6.5%	7.3%	7.3%	5.1%	6.0%	6.4%	7.4%	6.1%	5.4%	*5.0%*	*5.5%*	Return on Total Cap'l	*6.5%*
10.7%	13.3%	14.1%	13.2%	8.1%	10.3%	11.2%	12.0%	10.7%	8.5%	*8.5%*	*9.5%*	Return on Shr. Equity	*11.5%*
10.7%	13.3%	14.1%	13.2%	8.1%	10.3%	11.2%	12.0%	10.7%	8.5%	*8.5%*	*9.5%*	Return on Com Equity [E]	*11.5%*
NMF	3.3%	5.0%	5.1%	NMF	2.1%	3.1%	3.9%	2.4%	.3%	*1.0%*	*2.0%*	Retained to Com Eq	*3.0%*
106%	75%	65%	61%	104%	80%	72%	67%	77%	97%	*90%*	*82%*	All Div'ds to Net Prof	*73%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-3.4	-.8	--
Avg. Indust. Use (Mw)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	8.94	8.84	8.50
Capacity at Peak (Mw)	4684	4668	4668
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+.7	+1.3	+1.5
Fixed Charge Cov. (%)	302	301	272

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-1.5%	-3.0%	*Nil*
"Cash Flow"	-2.0%	2.5%	*3.5%*
Earnings	-2.0%	.5%	*4.0%*
Dividends	-3.5%	2.5%	*2.5%*
Book Value	-1.5%	3.0%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	796.1	885.7	911.4	750.2	3343.4
2012	697.1	752.5	858.6	688.4	2996.6
2013	661.1	735.9	765.9	688.4	2851.3
2014	578.0	605.7	687.2	*679.1*	*2550*
2015	*700*	*700*	*750*	*700*	*2850*

Cal-endar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.24	.36	.42	.25	1.27
2012	.20	.30	.42	.22	1.14
2013	.19	.24	.29	.20	.92
2014	.22	.27	.32	*.19*	*1.00*
2015	*.27*	*.28*	*.33*	*.22*	*1.10*

Cal-endar	QUARTERLY DIVIDENDS PAID [B] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.20	.205	.205	.205	.82
2011	.205	.215	.215	.215	.85
2012	.22	.22	.22	.22	.88
2013	.22	.22	.22	.22	.88
2014	.22	.22	.22		

BUSINESS: TECO Energy, Inc. is a holding company for Tampa Electric, which serves 700,000 customers in west central Florida, and Peoples Gas, which serves 350,000 customers in Florida. Acq'd New Mexico Gas (513,000 customers) 9/14. Sold TECO Transport 12/07; discontinued generation investments in Guatemala in '12; discontinued TECO Coal in '14. Electric revenue breakdown: residential, 49%; commercial, 31%; industrial, 9%; other, 11%. Generating sources: coal, 56%; gas, 36%; purchased, 8%. Fuel costs: 31% of revs. '13 reported deprec. rate (utility): 3.7%. Has 3,900 employees. Chairman: Sherrill W. Hudson. Pres. & CEO: John B. Ramil. Inc.: FL. Address: TECO Plaza, 702 N. Franklin St., Tampa, FL 33602. Tel.: 813-228-1111. Web: www.tecoenergy.com.

TECO Energy has agreed to sell its coal mining subsidiary. TECO Coal was once a solid contributor to corporate profits, but has been hurt lately by weaker demand. TECO will receive $120 million in cash once the deal closes (probably by yearend), plus up to $50 million more through 2019, depending on any improvement in coal prices. TECO Coal's results (including a $64.8 million aftertax loss on the sale) are now *excluded* from our presentation as discontinued operations. TECO will record additional one-time charges in the fourth quarter. We have restated revenues in the first two quarters of 2014 to exclude TECO Coal. Its effect on profits in that time frame was insignificant.

The market reaction to the sale has been favorable. TECO Coal's declining results were hurting the stock for much of 2014, but since the sale announcement in October, the share price is up 8%.

TECO completed the acquisition of New Mexico Gas in early September. The company paid $750 million in cash and assumed $200 million in debt for the utility, which serves 513,000 customers. TECO financed the deal with a combination of debt and equity. The purchase should be modestly accretive to earnings in the fourth quarter of 2014 and in 2015. We have raised our 2014 and 2015 share-earnings estimates by $0.05 and $0.10, respectively. TECO should benefit from the absence of acquisition costs ($5.7 million in the first nine months of 2014) and expense reductions arising from merger-related synergies.

The utilities in Florida are performing well. Tampa Electric and Peoples Gas are likely to earn above the midpoint of their allowed returns on equity (shown in the footnotes) this year. The economic recovery in Florida has stimulated customer growth of 1.6% (electric) and 1.9% (gas).

When will the next dividend increase occur? We aren't estimating a hike in 2015, due to the company's high payout ratio, but don't rule one out, either. TECO benefits from tax-loss carryforwards.

TECO stock offers a dividend yield that is a percentage point above the utility average. Total return potential to 2017-2019 is modest, but well above the norm for utility equities.

Paul E. Debbas, CFA *November 21, 2014*

(A) Diluted earnings. Excl. nonrecurring gain (losses): '99, (11¢); '03, ($4.97); '07, 63¢; '10, (2¢) net; gains (losses) on discont. ops.: '04, (77¢); '05, 31¢; '06, 1¢; '07, 7¢; '12, (15¢). Next earnings report due early Feb. (B) Div'ds paid in late Feb., May, Aug., & Nov. ■ Div'd reinv. plan avail. (C) Incl. def'd charges. In '13: $1.93/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '13 (elec.): 10.25%-12.25%; in '09 (gas): 9.75%-11.75%; in NM in '12: 10% (implied); earned on avg. com. eq., '13: 8.6%. Regulatory Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	75

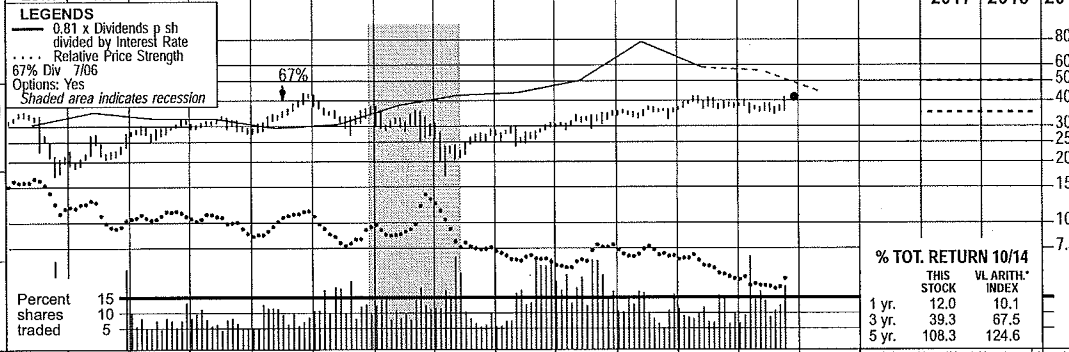
UIL HOLDINGS NYSE-UL

RECENT PRICE	41.63	P/E RATIO	16.5 (Trailing: 21.2; Median: 17.0)	RELATIVE P/E RATIO	0.91	DIV'D YLD	4.2%	VALUE LINE

TIMELINESS 3 Lowered 4/4/14
SAFETY 2 Raised 2/29/08
TECHNICAL 3 Lowered 10/24/14
BETA .80 (1.00 = Market)

High:	27.6	32.8	33.7	43.8	43.0	37.8	31.2	31.3	35.8	37.7	42.1	42.6		
Low:	18.5	25.1	27.4	27.4	27.0	25.1	17.0	23.8	28.6	32.3	35.9	34.3		

Target Price Range
2017 | 2018 | 2019



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+20%)	8%
Low	35	(-15%)	Nil

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	1	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2013	1Q2014	2Q2014
to Buy	95	111	93
to Sell	70	69	86
Hld's(000)	37878	40064	38533

% TOT. RETURN 10/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	12.0	10.1
3 yr.	39.3	67.5
5 yr.	108.3	124.6

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
29.34	29.01	37.54	46.15	47.55	40.39	45.87	49.88	34.03	39.23	37.69	29.91	19.75	31.01	29.22	28.52	*29.05*	*29.95*	Revenues per sh	*33.50*
5.34	4.67	5.53	6.61	5.89	4.69	4.37	4.13	4.65	5.48	5.93	5.09	3.65	5.33	5.65	5.51	*5.70*	*5.90*	"Cash Flow" per sh	*6.45*
1.80	2.23	2.56	2.53	1.85	1.24	1.54	1.30	1.86	1.87	1.89	1.94	1.99	1.96	2.02	2.28	*2.20*	*2.50*	Earnings per sh A	*2.75*
1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	*1.73*	*1.73*	Div'd Decl'd per sh B ■	*1.73*
1.63	1.48	2.31	2.01	2.41	2.19	2.04	2.25	3.09	9.92	8.57	4.12	4.03	6.48	5.67	5.38	*5.20*	*5.45*	Cap'l Spending per sh	*7.90*
19.05	19.55	20.42	21.25	20.28	20.65	22.84	22.39	18.53	18.55	18.85	19.15	21.31	21.61	21.95	23.85	*24.45*	*25.30*	Book Value per sh C	*29.05*
23.39	23.44	23.46	23.53	23.79	23.86	24.01	24.32	24.86	25.03	25.17	29.98	50.51	50.65	50.87	56.75	*56.75*	*56.75*	Common Shs Outst'g E	*56.75*
16.3	12.6	10.8	11.5	15.0	18.0	18.7	23.5	18.7	18.4	16.7	12.7	14.0	16.4	17.2	16.9	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.85	.72	.70	.59	.82	1.03	.99	1.25	1.01	.98	1.01	.85	.89	1.03	1.09	.95	*Value Line*		Relative P/E Ratio	*1.00*
5.9%	6.2%	6.2%	5.9%	6.2%	7.7%	6.0%	5.7%	5.0%	5.0%	5.5%	7.0%	6.2%	5.4%	4.9%	4.5%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $1720 mill. **Due in 5 Yrs.** $131.9 mill.
LT Debt $1714 mill. **LT Interest** $75.0 mill.
(LT interest earned: 3.0x)
Leases, Uncapitalized: Ann. rentals $4.5 mill.

Pension Assets-12/13 $688 mill. **Oblig.** $859 mill.

Pfd Stock None

Common Stock 56,546,266 shs.
as of 10/31/14

MARKET CAP: $2.4 billion (Mid Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
1101.3	1213.1	846.0	982.0	948.7	896.6	997.7	1570.4	1486.5	1618.7	*1650*	*1700*	Revenues ($mill)	*1900*
36.9	31.4	45.4	46.7	48.1	54.3	70.3	99.7	103.7	120.3	*120*	*135*	Net Profit ($mill)	*165*
45.4%	44.1%	31.2%	39.5%	42.2%	38.0%	38.6%	38.5%	41.9%	37.7%	*38.0%*	*40.0%*	Income Tax Rate	*40.0%*
1.1%	9.0%	8.0%	8.3%	8.3%	10.0%	26.3%	12.1%	12.1%	10.0%	*10.0%*	*10.0%*	AFUDC % to Net Profit	*10.0%*
47.2%	47.2%	47.0%	50.8%	53.6%	54.0%	58.4%	58.6%	58.9%	56.0%	*58.0%*	*58.0%*	Long-Term Debt Ratio	*58.0%*
52.8%	52.8%	53.0%	49.2%	46.4%	46.0%	41.6%	41.4%	41.1%	44.0%	*42.0%*	*42.0%*	Common Equity Ratio	*42.0%*
1039.6	1031.5	869.2	943.6	1023.6	1247.7	2587.9	2642.7	2716.9	3077.7	*3285*	*3430*	Total Capital ($mill)	*3955*
563.9	592.1	647.0	878.4	1073.6	1153.0	2327.5	2570.4	2787.4	3068.7	*3220*	*3365*	Net Plant ($mill)	*3915*
4.5%	4.1%	6.5%	6.2%	6.1%	5.8%	3.7%	5.2%	5.4%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
6.7%	5.8%	9.9%	10.1%	10.1%	9.5%	6.5%	9.1%	9.3%	8.9%	*9.0%*	*9.5%*	Return on Shr. Equity	*10.0%*
6.7%	5.8%	9.9%	10.1%	10.1%	9.5%	6.5%	9.1%	9.3%	8.9%	*9.0%*	*9.5%*	Return on Com Equity D	*10.0%*
NMF	NMF	NMF	3.1%	1.0%	1.2%	1.7%	1.1%	1.5%	2.4%	*2.5%*	*3.5%*	Retained to Com Eq	*4.5%*
112%	NMF	117%	70%	90%	88%	74%	88%	84%	73%	*70%*	*65%*	All Div'ds to Net Prof	*55%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-2.8	-2.6	-.16
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.4	7.1	7.8
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	Nil	+.2	+1.6
Fixed Charge Cov. (%)	230	249	262

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-4.0%	-4.5%	2.0%
"Cash Flow"	-.5%	.5%	2.5%
Earnings	1.0%	2.0%	4.5%
Dividends	--	--	Nil
Book Value	1.0%	4.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	561.1	314.0	321.4	373.9	1570.4
2012	458.3	283.5	323.8	420.9	1486.5
2013	548.0	319.1	316.5	435.1	1618.7
2014	571.2	334.8	293.0	*451*	*1650*
2015	*590*	*330*	*360*	*420*	*1700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	1.02	.28	.24	.42	1.96
2012	.92	.23	.31	.56	2.02
2013	1.01	.35	.31	.61	2.28
2014	.97	.16	.22	*.85*	*2.20*
2015	*1.10*	*.35*	*.40*	*.65*	*2.50*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.432	.432	.432	.432	1.73
2011	.432	.432	.432	.432	1.73
2012	.432	.432	.432	.432	1.73
2013	.432	.432	.432	.432	1.73
2014	.432	.432	.432		

BUSINESS: UIL Holdings, through its subsidiaries, operates as one of the largest regulated utility companies in Connecticut. Business consists of electric distribution/transmission operations of The United Illuminating Company and natural gas transportation/distribution operations of The Southern Connecticut Gas Company, The Connecticut Natural Gas Company, and The Berkshire Gas Company. Revenue distribution by class: residential, 49%; commercial, 24%; industrial, 6%; other, 21%. Fuel costs: 36% of revenues; O&M costs, 24%. Has 1,895 employees as of 12/13. President & Chief Executive Officer: James P. Torgerson. Inc.: CT. Address: 157 Church Street, P.O. Box 1564, New Haven, CT. 06506-0901. Telephone: 203-499-2000. Internet: www.uil.com.

UIL Holdings has decided to continue to pursue its asset purchase agreement with the City of Philadelphia. On October 27th, the proposed acquisition of Philadelphia Gas Works (PGW), which was subject to approvals by the Pennsylvania Public Utility Commission and the Philadelphia City Council, was rejected by the city's regulators. The Council announced that it would not sanction the planned asset purchase agreement, according to which UIL Holdings would acquire Philadelphia Gas Works for a cash price of $1.86 billion. The transaction was expected to enhance the scope of UIL's operations by expanding its natural gas business. That said, the utility company recently announced that it intends to continue pursuing the Philadelphia Gas Works transaction, as the deal would be strategically beneficial for UIL Holdings in the long term. The City Council still has time to consider its decision in its upcoming meetings. However, without the council's approval the purchase agreement will terminate automatically on December 31st, 2014,

We have lowered our full-year share-net estimate. Management recently narrowed its guidance for 2014 to $2.17-$2.33 per share, from its earlier guidance of $2.15-$2.35. So far in 2014, earnings have been impacted by higher-than-anticipated uncollectible expenses. This is largely due to higher customer bills owing to a cold winter and a bankruptcy in the electric business. Our share-net estimate for 2014 of $2.20 is at the lower end of the company's new target range. Additionally, even though the PGW transaction would be accretive to earnings in the long term, our estimates do not reflect the potential Philadelphia Gas Works acquisition.

This equity is currently an attractive selection for income-oriented investors. This neutrally ranked stock offers a strong dividend compared to others in the utility industry. Its dividend yield of approximately 4.2% is currently above the utility industry average. Moreover, this equity bears an Above-Average rank for Safety (2) and Financial Strength (B++). Income oriented accounts looking for a conservative investment may want to consider this stock.

Saumya Ajila *November 21, 2014*

(A) EPS basic. Excl. nonrecur. gains (losses): '00, 4¢; '03, (26¢); '04, $2.14; '06, ($5.07); '10, (47¢). Next egs. report due in late Feb. (B) Div'ds historically paid in early March, June, Sept., and Dec. ■ Div'd reinvest. plan avail. (C) Incl. deferred charges. In '13: $339.2 mill. or $5.98/sh. (D) Rate base: orig. cost. Rate allowed on common equity in '13: 9.15%. Earned on average common equity in '13: 8.5%. Regul. Clim.: Below Average. (E) In millions. Adjusted for stock dividend.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	45
Earnings Predictability	85

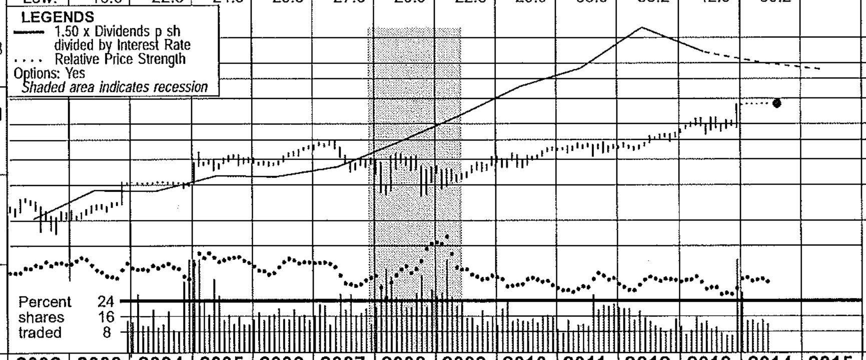
UNS ENERGY NYSE-UNS

RECENT PRICE 60.41 | P/E RATIO 19.4 (Trailing: 19.2 / Median: 18.0) | RELATIVE P/E RATIO 1.03 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS – Suspended 12/20/13
SAFETY 3 New 12/31/04
TECHNICAL – Suspended 12/20/13
BETA .75 (1.00 = Market)

High:	24.9	24.9	34.8	37.5	40.0	34.5	33.3	36.9	39.3	43.6	60.0	60.8		
Low:	16.0	22.9	24.3	29.5	27.6	20.9	22.8	29.0	33.0	35.2	42.5	59.2		

Target Price Range 2017 | 2018 | 2019



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+10%)	5%
Low	45	(-25%)	-3%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	1	0	0
to Sell	0	0	0	0	0	0	2	0	0

Institutional Decisions

	3Q2013	4Q2013	1Q2014
to Buy	109	96	74
to Sell	80	109	106
Hld's(000)	37570	38280	38587

% TOT. RETURN 6/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	39.5	25.1
3 yr.	82.1	52.6
5 yr.	179.8	168.7

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
23.83	24.85	31.12	43.12	25.50	28.71	34.13	35.26	37.42	39.12	39.41	38.89	39.78	40.89	35.36	35.74	*36.40*	*37.60*	Revenues per sh	*41.20*
3.48	3.96	4.23	5.41	4.80	5.20	5.29	5.21	5.68	5.64	4.56	7.82	7.33	7.44	6.48	7.33	*7.35*	*7.60*	"Cash Flow" per sh	*8.00*
.68	1.08	1.27	1.79	.97	1.30	1.31	1.30	1.85	1.55	.39	2.69	2.82	2.75	2.20	3.04	*3.12*	*3.40*	Earnings per sh A	*3.80*
--	--	.32	.40	.50	.60	.64	.76	.84	.90	.96	1.16	1.56	1.68	1.72	1.74	*1.85*	*1.95*	Div'd Decl'd per sh B ■ †	*2.28*
2.52	2.87	3.19	3.63	3.36	4.06	4.49	5.83	6.77	6.95	9.85	8.01	7.26	10.13	7.43	7.85	*9.45*	*8.05*	Cap'l Spending per sh	*7.85*
7.65	10.02	11.20	12.68	13.05	15.97	16.95	17.68	18.59	19.54	19.16	20.94	22.46	24.07	25.77	27.22	*27.00*	*28.20*	Book Value per sh	*32.70*
32.26	32.35	33.22	33.50	33.58	33.79	34.26	34.87	35.19	35.32	35.46	35.85	36.54	36.92	41.34	41.54	*41.50*	*42.00*	Common Shs Outst'g C	*42.50*
23.3	10.8	11.8	10.8	18.2	14.6	18.7	23.9	17.7	22.0	NMF	10.4	11.6	13.3	17.8	15.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
1.21	.62	.77	.55	.99	.83	.99	1.27	.96	1.17	NMF	.69	.74	.83	1.13	.89	*Value Line*		Relative P/E Ratio	*.90*
--	--	2.1%	2.1%	2.8%	3.2%	2.6%	2.5%	2.6%	2.6%	3.3%	4.1%	4.8%	4.6%	4.4%	3.6%	*estimates*		Avg Ann'l Div'd Yield	*4.1%*

CAPITAL STRUCTURE as of 12/31/13
Total Debt $1806.6 mill. **Due in 5 Yrs** $477.0 mill.
LT Debt $1733.3 mill. **LT Interest** $71.0 mill.
Incl. $73.9 mill. capitalized leases.

(LT interest earned: 3.0x)

Pension Assets-12/13 $323 mill. **Oblig.** $352 mill.
Pfd Stock None

Common Stock 41,701,718 shs.
as of 4/17/14
MARKET CAP: $2.5 billion (Mid Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
1169.0	1229.5	1316.9	1381.4	1397.5	1394.4	1453.7	1509.5	1461.8	1484.6	*1510*	*1580*	Revenues ($mill)	*1750*
45.9	46.1	69.2	58.4	14.0	104.3	111.5	110.0	90.9	127.5	*125*	*140*	Net Profit ($mill)	*160*
42.5%	41.4%	38.8%	40.1%	54.8%	38.2%	41.2%	37.8%	38.0%	31.4%	*38.0%*	*38.0%*	Income Tax Rate	*40.0%*
--	--	2.9%	3.4%	--	--	--	--	--	--	*Nil*	*Nil*	AFUDC % to Net Profit	*Nil*
77.1%	75.3%	72.9%	68.8%	72.9%	70.5%	68.5%	67.8%	62.3%	59.4%	*62.0%*	*62.5%*	Long-Term Debt Ratio	*63.0%*
22.9%	24.7%	27.1%	31.2%	27.1%	29.5%	31.5%	32.2%	37.7%	40.6%	*38.0%*	*37.5%*	Common Equity Ratio	*37.0%*
2540.3	2494.9	2414.1	2214.9	2506.4	2547.0	2602.8	2758.6	2826.0	2787.6	*2950*	*3180*	Total Capital ($mill)	*3740*
2081.1	2171.5	2259.6	2407.3	2617.7	2785.7	2961.5	3182.3	3300.4	3534.8	*3450*	*3625*	Net Plant ($mill)	*4200*
5.1%	5.1%	5.9%	5.7%	3.0%	5.2%	5.5%	5.3%	4.5%	5.8%	*6.0%*	*6.0%*	Return on Total Cap'l	*5.5%*
7.9%	7.5%	10.6%	8.5%	2.1%	13.9%	13.6%	12.4%	8.5%	11.3%	*11.0%*	*12.0%*	Return on Shr. Equity	*11.5%*
7.9%	7.5%	10.6%	8.5%	2.1%	13.9%	13.6%	12.4%	8.5%	11.3%	*11.0%*	*12.0%*	Return on Com Equity D	*11.5%*
4.1%	3.2%	6.1%	3.9%	NMF	8.4%	6.7%	5.4%	2.0%	4.9%	*4.5%*	*5.5%*	Retained to Com Eq	*4.5%*
48%	57%	43%	54%	NMF	40%	51%	56%	77%	57%	*58%*	*53%*	All Div'ds to Net Prof	*60 %*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+.4	-.7	+.1
Avg. Indust. Use (MWH)	5060	5086	5090
Avg. Indust. Revs. per KWH (¢)	7.10	7.20	7.20
Capacity at Peak (Mw)	3271	2950	3015
Peak Load, Summer (Mw)	2334	2290	2230
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+.4	+.5	+.8
Fixed Charge Cov. (%)	251	239	291

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	1.5%	-0.5%	*1.5%*
"Cash Flow"	3.5%	6.0%	*2.0%*
Earnings	7.0%	16.0%	*6.0%*
Dividends	13.0%	13.5%	*5.0%*
Book Value	6.5%	6.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	344.8	369.7	450.9	344.1	1509.5
2012	315.4	364.0	434.1	348.3	1461.8
2013	332.1	365.2	437.0	350.2	1484.6
2014	333.4	*370*	*450*	*356.6*	*1510*
2015	*350*	*375*	*485*	*370*	*1580*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.35	.71	1.46	.22	2.75
2012	.17	.64	1.21	.18	2.20
2013	.27	.83	1.62	.32	3.04
2014	.37	*.75*	*1.67*	*.33*	*3.12*
2015	*.45*	*.80*	*1.65*	*.50*	*3.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.39	.39	.39	.39	1.56
2011	.42	.42	.42	.42	1.68
2012	.43	.43	.43	.43	1.72
2013	.435	.435	.435	.435	1.74
2014	.48	.48			

BUSINESS: UNS Energy Corporation, through its subsidiaries, operates as an electric utility in Arizona. Subsidiaries include Tucson Electric Power (TEP), UNS Gas, and UNS Electric. '13 retail customers: TEP, 413,000 (in southeastern Arizona); UNS Gas, 149,000; UNS Electric, 93,000. Revenue sources: residential, 42%; commercial, 23%; industrial, 35%. Copper mining is largest industry served. Fuels: coal, 75%; gas, 8%; purchased power, 17%. '13 TEP reported depreciation rate: 4.0%. Has 1,977 employees: TEP, 1,398; UNS Gas, 188; UNS Electric, 143; Other, 248. Chrmn. & CEO: David G. Hutchens. Inc.: AZ. Address: 88 E. Broadway Blvd., Tucson, AZ 85701. Telephone: 520-571-4000. Internet: www.uns.com.

The acquisition of UNS Energy by Canada-based Fortis Inc. moves closer toward completion. Fortis would pay $60.25 in cash for each UNS share. Indeed, the purchase seems to be moving to culmination at a reasonable pace since the takeover announcement in December, 2013. Most recently, UNS Energy and Fortis filed a settlement agreement with Arizona Corporation Commission (ACC) on May 16th, related to the intended acquisition. As part of the settlement, UNS Energy and Fortis have agreed to provide customer-bill credits amounting to $30 million over a period of five years. Upon completion of the deal, clients of Tucson Electric Power (TEP) and UniSource Energy Services (UES) are expected to get bill credits equaling $10 million in the first year and $5 million a year over the remaining four years. Fortis is also expected to strengthen UNS Energy's balance sheet by $220 million from the originally-agreed amount of $200 million. If approved, the settlement is set to be completed by September.

The takeover is expected to be finalized by the end of 2014. The $4.3 billion transaction, in which Fortis will assume $1.8 billion in debt and UNS equity of $2.5 billion, was approved by shareholders on March 26th. It was followed by the approval of the Federal Energy Regulatory Commission and that of the Commission on Foreign Investment. A green light from the ACC is one of the last regulatory hurdles remaining.

The deal should give UNS Energy and its subsidiaries access to new resources and capital. As per Arizona's renewable energy standard, utilities are expected to reduce reliance on coal and natural gas for energy generation, and increase their use of renewable energy to 15% by 2025. Significant investments will be required toward this move.

We have suspended the Timeliness rank for this issue due to the impending acquisition. This stock is currently trading above the deal price. We suggest investors sell their holdings at the present level, as there is not much room for capital gains right now. Moreover, selling at the current price will eliminate any downside risk, in case the transaction falls through.

Saumya Ajila *August 1, 2014*

(A) EPS diluted. Excl. nonrecur. gains: '98, 19¢; '99, $1.35; '00, 48¢; '03, $2.00. Next earnings report due early November. Earnings may not sum due to rounding. (B) Div'ds historically paid in Mar., June, Sept., and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) In millions. (D) Rate base: fair value. Rate allowed on com. eq. in '13: 10.0%; earned on avg. com. eq., '13: 8.5%. Regulatory Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	80
Earnings Predictability	40

Staff/209
Muldoon/44

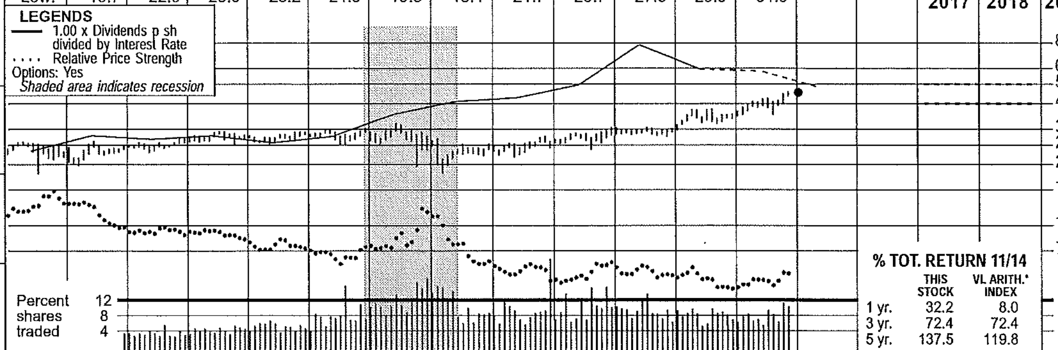
VECTREN CORP. NYSE-VVC

RECENT PRICE 45.46 | P/E RATIO 19.9 (Trailing: 23.6; Median: 16.0) | RELATIVE P/E RATIO 1.08 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 2 Lowered 11/21/14
SAFETY 2 Lowered 1/5/01
TECHNICAL 3 Raised 12/5/14
BETA .80 (1.00 = Market)

High:	26.1	27.1	29.5	29.3	30.5	32.2	26.9	27.8	30.7	30.8	37.9	46.0
Low:	19.7	22.9	25.0	25.2	24.8	19.5	18.1	21.7	23.7	27.5	29.5	34.6

Target Price Range 2017 | 2018 | 2019



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+10%)	6%
Low	40	(-10%)	1%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	121	102	122
to Sell	115	127	112
Hld's(000)	47921	48584	49433

% TOT. RETURN 11/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	32.2	8.0
3 yr.	72.4	72.4
5 yr.	137.5	119.8

Vectren was formed on March 31, 2000 through the merger of Indiana Energy and SIGCORP. The merger was consummated with a tax-free exchange of shares and has been accounted for as a pooling of interests. Indiana Energy common stockholders received one Vectren common share for each share held. SIGCORP stockholders exchanged each common share for 1.333 common shares of Vectren.

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
22.26	26.62	26.83	29.88	30.67	25.76	26.06	28.39	27.16	30.23	31.65	32.75	Revenues per sh	39.55
3.27	3.87	3.69	4.29	3.97	4.40	4.44	4.71	5.03	5.03	5.55	6.15	"Cash Flow" per sh	7.45
1.42	1.81	1.44	1.83	1.63	1.79	1.65	1.73	1.94	1.66	2.05	2.40	Earnings per sh A	3.00
1.15	1.19	1.23	1.27	1.31	1.35	1.37	1.39	1.41	1.43	1.45	1.54	Div'd Decl'd per sh B■†	1.75
3.66	3.04	3.70	4.38	4.83	5.33	3.39	3.92	4.45	4.77	4.80	5.25	Cap'l Spending per sh	7.00
14.42	15.01	15.43	16.16	16.68	17.23	17.61	17.89	18.57	18.86	19.30	19.95	Book Value per sh C	21.50
75.90	76.19	76.10	76.36	81.03	81.10	81.70	81.90	82.20	82.40	83.00	84.00	Common Shs Outst'g D	86.00
17.6	15.1	18.9	15.3	16.8	12.9	15.0	15.8	15.0	20.7	Bold figures are		Avg Ann'l P/E Ratio	15.0
.93	.80	1.02	.81	1.01	.86	.95	.99	.95	1.16	Value Line		Relative P/E Ratio	.95
4.6%	4.4%	4.5%	4.5%	4.8%	5.9%	5.5%	5.1%	4.8%	4.2%	estimates		Avg Ann'l Div'd Yield	3.9%
1689.8	2028.0	2041.6	2281.9	2484.7	2088.9	2129.5	2325.2	2232.8	2491.2	2625	2750	Revenues ($mill)	3400
108.0	136.8	108.8	143.1	129.0	145.0	133.7	141.6	159.0	136.6	170	200	Net Profit ($mill)	260
26.5%	24.4%	21.8%	34.7%	37.1%	26.5%	35.8%	37.9%	34.2%	32.9%	35.0%	35.0%	Income Tax Rate	35.0%
3.0%	1.4%	3.8%	2.8%	2.9%	4.1%	--	--	4.1%	4.0%	4.0%	4.0%	AFUDC % to Net Profit	4.0%
48.1%	51.2%	50.7%	50.2%	48.0%	52.4%	49.9%	51.6%	50.4%	53.3%	51.0%	52.0%	Long-Term Debt Ratio	53.0%
51.8%	48.8%	49.3%	49.8%	52.0%	47.6%	50.1%	48.4%	49.6%	46.7%	49.0%	48.0%	Common Equity Ratio	47.0%
2111.5	2341.3	2382.2	2479.1	2599.5	2937.7	2874.1	3025.1	3079.5	3331.4	3250	3500	Total Capital ($mill)	3950
2156.2	2251.9	2385.5	2539.7	2720.3	2878.8	2955.4	3032.6	3119.6	3224.3	3400	3550	Net Plant ($mill)	4000
6.4%	7.2%	6.0%	7.2%	6.5%	6.3%	6.1%	6.2%	6.4%	5.4%	6.5%	7.0%	Return on Total Cap'l	8.0%
9.9%	12.0%	9.3%	11.6%	9.5%	10.4%	9.3%	9.7%	10.4%	8.8%	10.5%	12.0%	Return on Shr. Equity	14.0%
9.9%	12.0%	9.3%	11.6%	9.5%	10.4%	9.3%	9.7%	10.4%	8.8%	10.5%	12.0%	Return on Com Equity E	14.0%
1.9%	4.0%	1.3%	3.8%	2.0%	2.6%	1.6%	1.9%	2.9%	1.2%	3.0%	4.5%	Retained to Com Eq	7.0%
81%	66%	86%	67%	80%	75%	83%	80%	73%	86%	71%	65%	All Div'ds to Net Prof	58%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $1639.7 mill. **Due in 5 Yrs** $710.0 mill.
LT Debt $1572.3 mill. **LT Interest** $85.0 mill.
(LT interest earned: 3.7x)

Pension Assets-12/13 $323.9 mill. **Oblig.** $338.4 mill.
Pfd Stock None

Common Stock 82,537,902 shs. **as of 10/31/14**

MARKET CAP: $3.8 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-.3	-2.3	+.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1494	1494	1384
Peak Load, Summer (Mw)	1220	1259	1102
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	--	+.4	+.6
Fixed Charge Cov. (%)	347	367	380

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	1.0%	-.5%	5.5%
"Cash Flow"	4.5%	4.5%	7.0%
Earnings	2.0%	1.5%	9.0%
Dividends	3.0%	2.0%	3.5%
Book Value	3.5%	3.0%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	682.6	475.8	539.4	627.4	2325.2
2012	604.6	470.6	513.5	644.1	2232.8
2013	700.6	531.0	579.6	680.0	2491.2
2014	796.8	542.5	595.6	690.1	2625
2015	810	575	625	740	2750

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.55	.18	.43	.57	1.73
2012	.62	.31	.48	.53	1.94
2013	.61	d.07	.52	.60	1.66
2014	.62	.14	.57	.72	2.05
2015	.68	.32	.62	.78	2.40

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.340	.340	.340	.345	1.37
2011	.345	.345	.345	.350	1.39
2012	.350	.350	.350	.355	1.41
2013	.355	.355	.355	.360	1.43
2014	.360	.360	.360	.380	

BUSINESS: Vectren is a holding company formed through the merger of Indiana Energy and SIGCORP. Supplies electricity and gas to an area nearly two-thirds of the state of Indiana. Owns gas distribution assets in Ohio. Has a customer base exceeding 1.1 million. 2013 Electricity revenues: residential, 36%; commercial, 27%; industrial, 35%; other, 2%. 2013 Gas revenues: residential, 67%; commercial, 24%; other, 9%. Also provides energy-related products and services and has an investment subsidiary. Est'd plant age: electric, 8 years. '13 deprec. rate: 5.2%. Has 5,500 employees. Chairman, President, & CEO: Carl Chapman. Incorporated: IN. Address: One Vectren Square, Evansville, Indiana 47708. Telephone: 812-491-4000. Internet: www.vectren.com.

Shares of Vectren have advanced nicely in price since the beginning of the year. We think investors have been pleased with the sale of Vectren Fuels to Sunrise Coal, LLC. This move completes the company's exit from commodity-based nonutility businesses. Its remaining operations should provide better growth potential with less volatility. Moreover, Vectren has reported healthy results in recent quarters. In the September period, the Nonutility group reported significant earnings growth, thanks to strength in the infrastructure services business. Meanwhile, the Utility group posted solid results, as well. Looking forward, we expect a favorable comparison for the fourth quarter and greater revenues and share net for full-year 2014.

Good performance ought to continue from 2015 onward. The Nonutility group should further benefit from strong results at the infrastructure services business. This operation will likely experience robust demand going forward, assuming relatively normal weather. The absence of Vectren Fuels should also be a plus for the Nonutility group. Elsewhere, the Utility group will probably post solid results. In particular, we expect the electric utility services line will perform well. Greater operating expenses will likely constrain earnings at the gas utility business, though modest customer growth and returns from Ohio infrastructure replacement programs are expected to provide some support.

The board of directors has increased the dividend by roughly 6%. Beginning with the December payout, the quarterly dividend is now $0.38 a share. Dividend growth will probably continue at Vectren going forward.

This issue is favorably ranked for year-ahead relative price performance. The equity's solid dividend yield may appeal to income-oriented accounts. Moreover, Vectren earns good marks for Safety, Financial Strength, Price Stability, and Earnings Predictability. However, long-term appreciation potential is below average here, as the stock is trading well within our Target Price Range. Investors seeking long-term capital appreciation should probably look elsewhere.

Michael Napoli, CFA *December 19, 2014*

(A) Diluted EPS. Excl. nonrecur. gain (loss): '03, (6¢); '09, 15¢. Next egs report due in February. (B) Div'ds historically paid in early March, June, September, and December. ■Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '13, $5.53/sh. (D) In millions. (E) Electric rate base determination: fair value. Rates allowed on elect. common equity range from 10.15% to 10.4%; earned on common equity in '13: 8.8%. Regulatory Climate: Above Average.

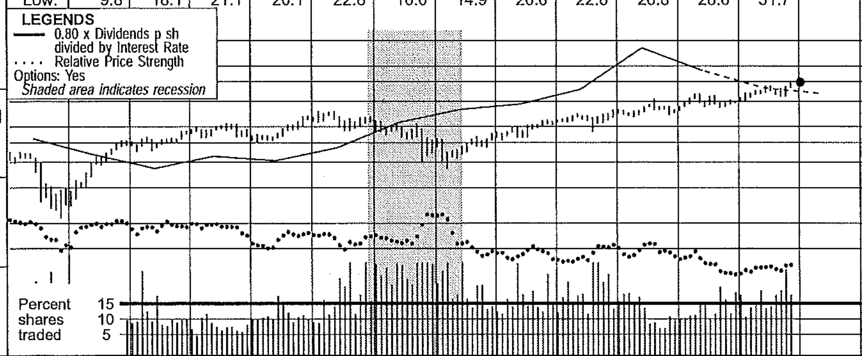
Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	85

WESTAR ENERGY NYSE-WR

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
39.79	16.4	(Trailing: 16.8) (Median: 14.0)	0.89	3.5%	VALUE LINE

TIMELINESS 3 Lowered 12/12/14
SAFETY 2 Raised 4/1/05
TECHNICAL 4 Lowered 11/28/14
BETA .75 (1.00 = Market)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
High:	20.5	22.9	25.0	27.2	28.6	25.9	22.3	25.9	29.0	33.0	35.0	39.8
Low:	9.8	18.1	21.1	20.1	22.8	16.0	14.9	20.6	22.6	26.8	28.6	31.7



Target Price Range
2017 | 2018 | 2019
64
48
40
32
24
20
16
12
8
6

2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+25%)	9%
Low	35	(-10%)	1%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	5	0	0	0	0	1	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	150	161	155
to Sell	133	116	117
Hld's(000)	88851	93488	95815

% TOT. RETURN 11/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	29.8	8.0
3 yr.	61.3	72.4
5 yr.	140.3	119.8

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
30.86	30.21	33.80	31.20	24.77	20.06	17.02	18.23	18.37	18.09	16.98	17.04	18.34	17.27	17.88	18.48	*19.70*	*19.85*	Revenues per sh	*20.75*
6.35	7.51	6.96	5.32	4.77	3.77	3.12	3.28	3.94	3.77	3.14	3.59	4.24	3.97	4.30	4.41	*4.55*	*4.70*	"Cash Flow" per sh	*5.10*
2.13	1.48	.89	d.58	1.00	1.48	1.17	1.55	1.88	1.84	1.31	1.28	1.80	1.79	2.15	2.27	*2.35*	*2.45*	Earnings per sh A	*2.90*
2.14	2.14	1.44	1.20	1.20	.87	.80	.92	.98	1.08	1.16	1.20	1.24	1.28	1.32	1.36	*1.39*	*1.44*	Div'd Decl'd per sh B■†	*1.60*
2.77	4.09	4.40	3.37	1.89	2.06	2.19	2.45	3.95	7.84	8.65	5.26	4.82	5.55	6.40	6.08	*6.50*	*7.00*	Cap'l Spending per sh	*8.15*
29.40	27.83	27.20	25.97	13.68	14.23	16.13	16.31	17.62	19.14	20.18	20.59	21.25	22.03	22.89	23.88	*24.00*	*25.60*	Book Value per sh C	*29.65*
65.91	67.40	70.08	70.08	71.51	72.84	86.03	86.84	87.39	95.46	108.31	109.07	112.13	125.70	126.50	128.25	*130.00*	*130.00*	Common Shs Outst'g E	*135.00*
18.4	17.2	20.6	--	14.0	10.8	17.4	14.8	12.2	14.1	17.0	14.9	13.0	14.8	13.4	14.0	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.96	.98	1.34	--	.76	.62	.92	.79	.66	.75	1.02	.99	.83	.93	.85	.79	*Value Line*		Relative P/E Ratio	*.95*
5.5%	8.4%	7.9%	5.8%	8.6%	5.5%	3.9%	4.0%	4.3%	4.2%	5.2%	6.3%	5.3%	4.8%	4.6%	4.3%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $3417.8 mill. **Due in 5 Yrs** $675.0 mill.
LT Debt $3215.4 mill. **LT Interest** $160.0 mill.
(LT interest earned: 3.3x)

Pension Assets 12/13 $548 mill. **Oblig.** $929 mill.

Pfd Stock None

Common Stock 130,196,193 shs.
MARKET CAP: $5.2 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
1464.5	1583.3	1605.7	1726.8	1839.0	1858.2	2056.2	2171.0	2261.5	2370.7	*2560*	*2580*	Revenues ($mill)	*2800*
100.1	134.9	165.3	168.4	136.8	141.3	203.9	214.0	275.1	292.5	*305*	*320*	Net Profit ($mill)	*390*
25.0%	31.0%	25.4%	27.5%	24.8%	29.4%	29.0%	35.2%	30.9%	33.1%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
--	--	--	10.4%	--	--	--	--	10.4%	10.0%	*10.0%*	*10.0%*	AFUDC % to Net Profit	*10.0%*
53.8%	52.1%	50.0%	50.6%	49.8%	53.4%	53.6%	49.5%	51.2%	50.0%	*50.5%*	*50.5%*	Long-Term Debt Ratio	*50.0%*
45.5%	47.2%	49.3%	48.9%	49.7%	46.1%	46.0%	50.1%	48.8%	50.0%	*49.0%*	*49.5%*	Common Equity Ratio	*50.0%*
3049.2	3000.4	3124.2	3738.3	4400.1	4866.8	5180.9	5531.0	5938.2	6131.1	*6275*	*6650*	Total Capital ($mill)	*8000*
3911.0	3947.7	4071.6	4803.7	5533.5	5771.7	6309.5	6745.4	7335.7	7848.5	*8000*	*8200*	Net Plant ($mill)	*9200*
5.5%	6.2%	6.7%	5.8%	4.2%	4.4%	5.5%	5.3%	6.0%	6.1%	*5.0%*	*5.0%*	Return on Total Cap'l	*6.0%*
7.1%	9.4%	10.6%	9.1%	6.2%	6.2%	8.5%	7.7%	9.5%	9.6%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.0%*
7.1%	9.5%	10.7%	9.2%	6.2%	6.3%	8.5%	7.7%	9.4%	9.6%	*9.5%*	*9.5%*	Return on Com Equity D	*9.5%*
3.2%	4.3%	5.5%	4.3%	1.2%	.8%	3.1%	2.7%	4.0%	4.2%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
56%	55%	49%	53%	80%	87%	63%	65%	57%	56%	*59%*	*59%*	All Div'ds to Net Prof	*55%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+1.0	-1.5	+3.6
Avg. Indust. Use (MWH)	5589	5588	5407
Avg. Indust. Revs. per KWH (¢)	6.22	6.60	6.47
Capacity at Peak (Mw)	6784	6557	6671
Peak Load, Summer (Mw)	5549	5411	5489
Annual Load Factor (%)	55.5	56.0	55.9
% Change Customers (yr-end)	+.1	+.2	+.2
Fixed Charge Cov. (%)	297	319	323

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-3.5%	--	*2.5%*
"Cash Flow"	-1.0%	3.0%	*4.5%*
Earnings	12.5%	4.5%	*6.0%*
Dividends	2.0%	4.0%	*3.0%*
Book Value	2.5%	4.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	481.7	524.9	678.2	486.2	2171.0
2012	475.7	566.3	695.8	523.7	2261.5
2013	546.2	569.6	695.0	559.9	2370.7
2014	628.6	612.7	764.0	*554.7*	*2560*
2015	*630*	*620*	*750*	*580*	*2580*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.27	.38	.98	.16	1.79
2012	.21	.48	1.09	.37	2.15
2013	.40	.52	1.04	.31	2.27
2014	.52	.40	1.10	*.33*	*2.35*
2015	*.50*	*.50*	*1.10*	*.35*	*2.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.30	.31	.31	.31	1.23
2011	.31	.32	.32	.32	1.27
2012	.32	.33	.33	.33	1.31
2013	.33	.34	.34	.34	1.35
2014	.34	.35	.35	.35	

BUSINESS: Westar Energy, Inc., formerly Western Resources, is the parent of Kansas Gas & Electric Company. Westar supplies electricity to 700,000 customers in Kansas. Electric revenue sources: residential and rural, 34%; commercial, 38%; industrial, 28%. Sold investment in ONEOK in 2003 and 85% ownership in Protection One in 2004. 2013 depreciation rate: 3.8%. Estimated plant age: 15 years. Fuels: coal, 52%; nuclear, 8%; gas, 40%. Has 2,302 employees. BlackRock Inc owns 7.0% of common; The Vanguard Group owns 5.8%; JP Morgan owns 5.2% (3/14 proxy). CEO and Pres.: Mark A. Ruelle. Inc.: Kansas. Addr.: 818 South Kansas Avenue, Topeka, Kansas 66612. Telephone: 785-575-6300. Internet: www.westarenergy.com.

Westar Energy reported third-quarter results that topped our forecasts. The Topeka, Kansas-based company posted earnings of $1.10 a share, on revenue of $764 million. Greater profits were driven largely by higher prices and lower operating and maintenance costs at the company's power plants. The electric utility's various investments on transmission infrastructure and air quality control are finally coming to fruition, with additional projects such as the LaCygne air-quality retrofit set to be completed next year.

Meanwhile, going forward, carbon control measures are a cause for concern. New rules put out by the Environmental Protection Agency (and backed by the current administration), will be tough to comply with in the future. Coal-based generation still represents about 65% of the fuel mix for Westar (as of the third quarter), but the company has worked hard to reduce that figure by about 8% when compared to last year. Importantly, the newly elected Republican Senate will likely put pressure on the government agency to either delay or repeal the new measures, and a compromise could be reached between the two parties at some time. However, as of right now, regulatory risk is still a big problem going forward for the entire industry.

The new year ought to have a number of upcoming catalysts. Management's guidance, which we believe is conservative, calls for retail sales to climb 150 basis points next year. Retail sales have risen roughly 3% through the first nine months of 2014. Moreover, operating and maintenance costs, as well as SG&A expenses, should continue to trend lower, as Westar focuses on keeping its overhead in check. Finally, management pointed to price increases in transmission and environmental cost recovery, which was approved by regulators, thereby allowing the utility to raise rates on certain residents in order to cover much of its environmental regulation outlay.

Utilities have done well this year, and Westar Energy is no exception. The stock has good marks for both Price Stability (100) and Safety (2), and would be a fine choice for investors in need of some income.

Daniel Henigson *December 19, 2014*

(A) EPS diluted from 2010 onward. Excl. nonrecur. gains (losses): '98, ($1.45); '99, ($1.31); '00, $1.07; '01, 27¢; '02, ($12.06); '03, 77¢; '08, 39¢; '11, 14¢. Earnings may not sum due to rounding. Next egs. rep't due early February. (B) Div'ds paid in early Jan., April, July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. reg. assets. In 2013: $4.92/sh. (D) Rate base determined: fair value; Rate allowed on common equity in '13: 10.0%; earned on avg. com. eq., '13: 9.5%. Regul. Clim.: Avg. (E) In mill.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	80

WISCONSIN ENERGY NYSE-WEC

RECENT PRICE **50.95** | P/E RATIO **20.5** (Trailing: 19.0 / Median: 15.0) | RELATIVE P/E RATIO **1.11** | DIV'D YLD **3.3%** | **VALUE LINE**

TIMELINESS	3 Lowered 9/19/14
SAFETY	1 Raised 3/23/12
TECHNICAL	4 Raised 12/12/14
BETA .65 (1.00 = Market)	

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
High:	16.8	17.3	20.4	24.3	25.2	24.8	25.3	30.5	35.4	41.5	45.0	51.4
Low:	11.3	14.8	16.7	19.1	20.5	17.4	18.2	23.4	27.0	33.6	37.0	40.2

Target Price Range 2017 | 2018 | 2019

2017-19 PROJECTIONS

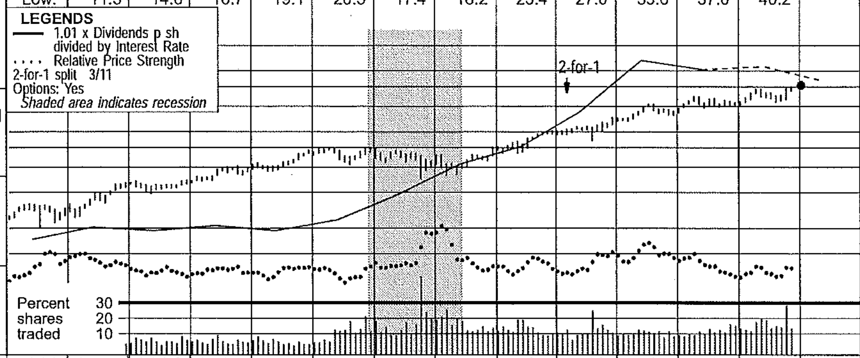
	Price	Gain	Ann'l Total Return
High	50	(Nil)	3%
Low	40	(-20%)	-1%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	2	4	0	0	0	0	0	2	0
to Sell	2	4	0	0	0	0	0	4	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	231	257	220
to Sell	200	186	224
Hld's(000)	168816	166724	174180



% TOT. RETURN 11/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.4	8.0
3 yr.	64.9	72.4
5 yr.	158.7	119.8

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
8.56	9.56	14.14	17.02	16.10	17.12	14.66	16.31	17.08	18.12	18.95	17.65	17.98	19.46	18.54	20.00	22.15	22.15	Revenues per sh	25.50
2.06	2.26	2.24	2.72	2.84	2.86	2.58	2.89	2.90	2.98	2.95	3.11	3.30	3.68	4.01	4.33	4.50	4.65	"Cash Flow" per sh	5.50
.83	.94	.54	.92	1.16	1.13	.93	1.28	1.32	1.42	1.52	1.60	1.92	2.18	2.35	2.51	2.60	2.70	Earnings per sh A	3.25
.78	.78	.69	.40	.40	.40	.42	.44	.46	.50	.54	.68	.80	1.04	1.20	1.45	1.56	1.69	Div'd Decl'd per sh B ■	2.10
1.76	2.22	2.64	3.01	2.54	2.95	2.85	3.40	4.17	5.28	4.86	3.50	3.41	3.60	3.09	3.04	3.30	3.65	Cap'l Spending per sh	3.75
8.23	8.44	8.50	8.91	9.22	9.96	10.65	11.46	12.35	13.25	14.27	15.26	16.26	17.20	18.05	18.73	19.65	20.60	Book Value per sh C	21.50
231.21	237.81	237.29	230.84	232.06	236.85	233.97	233.96	233.94	233.89	233.84	233.82	233.77	230.49	229.04	225.96	225.50	225.50	Common Shs Outst'g D	220.00
18.0	13.3	18.7	12.1	10.5	12.4	17.5	14.5	16.0	16.5	14.8	13.3	14.0	14.2	15.8	16.5	Bold figures are		Avg Ann'l P/E Ratio	14.5
.94	.76	1.22	.62	.57	.71	.92	.77	.86	.88	.89	.89	.89	.89	1.01	.93	Value Line		Relative P/E Ratio	.90
5.2%	6.3%	6.8%	3.6%	3.3%	2.8%	2.6%	2.4%	2.2%	2.1%	2.4%	3.2%	3.0%	3.3%	3.2%	3.5%	estimates		Avg Ann'l Div'd Yield	4.5%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $5093.1 mill. Due in 5 Yrs $1625.5 mill.
LT Debt $4569.6 mill. LT Interest $251.3 mill.
Incl. $84.5 mill. capitalized leases.
(LT interest earned: 5.0x)
Leases, Uncapitalized Annual rentals $3.9 mill.
Pension Assets-12/13 $1451.0 mill. Oblig. $1410.2 mill.
Pfd Stock $30.4 mill. Pfd Div'd $1.2 mill.
260,000 shs. 3.60%, $100 par, callable at $101; 44,498 shs. 6%, $100 par.
Common Stock 225,517,341 shs.

MARKET CAP: $11 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
3431.1	3815.5	3996.4	4237.8	4431.0	4127.9	4202.5	4486.4	4246.4	4519.0	5000	5000	Revenues ($mill)	5600
221.2	304.8	313.7	337.7	359.8	378.4	455.6	514.0	547.5	578.6	595	610	Net Profit ($mill)	730
37.5%	32.9%	35.8%	39.1%	37.6%	36.5%	35.4%	33.9%	35.9%	36.9%	38.0%	38.0%	Income Tax Rate	38.0%
10.0%	12.5%	19.0%	23.8%	27.2%	25.0%	18.6%	16.8%	9.4%	4.5%	6.0%	6.0%	AFUDC % to Net Profit	5.0%
56.2%	52.8%	51.3%	50.3%	54.8%	51.9%	50.6%	53.6%	51.7%	50.6%	48.5%	49.5%	Long-Term Debt Ratio	49.0%
43.3%	46.7%	48.2%	49.2%	44.8%	47.7%	49.0%	46.0%	48.0%	49.1%	51.0%	50.5%	Common Equity Ratio	50.5%
5762.3	5741.5	5992.8	6302.1	7442.0	7473.1	7764.5	8608.0	8619.3	8626.6	8650	9245	Total Capital ($mill)	9400
5903.1	6362.9	7052.5	7681.2	8517.0	9070.5	9601.5	10160	10572	10907	11225	11625	Net Plant ($mill)	12575
5.6%	7.0%	6.6%	7.0%	6.3%	6.4%	7.5%	7.5%	7.9%	8.1%	8.0%	8.0%	Return on Total Cap'l	9.0%
8.8%	11.2%	10.7%	10.8%	10.7%	10.5%	11.9%	12.9%	13.1%	13.6%	13.5%	13.0%	Return on Shr. Equity	15.0%
8.8%	11.3%	10.8%	10.9%	10.7%	10.6%	12.0%	12.9%	13.2%	13.6%	13.5%	13.0%	Return on Com Equity E	15.5%
4.9%	7.5%	7.1%	7.1%	7.0%	6.2%	7.0%	6.8%	6.5%	5.9%	5.5%	5.0%	Retained to Com Eq	5.5%
45%	34%	35%	35%	35%	42%	41%	47%	51%	57%	59%	63%	All Div'ds to Net Prof	64%

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-.5	-.6	-4.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.64	7.66	8.21
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.2	+.3	+.2
Fixed Charge Cov. (%)	336	377	414

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	1.5%	1.5%	4.5%
"Cash Flow"	3.5%	6.5%	5.5%
Earnings	8.0%	10.5%	5.5%
Dividends	12.0%	19.5%	9.5%
Book Value	7.0%	6.0%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	1328.7	991.7	1052.8	1113.2	4486.4
2012	1191.2	944.7	1039.3	1071.2	4246.4
2013	1275.2	1012.3	1053.2	1178.3	4519.0
2014	1695.0	1043.7	1033.3	1228	5000
2015	1500	1100	1150	1250	5000

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.72	.41	.55	.49	2.18
2012	.74	.51	.67	.43	2.35
2013	.76	.52	.60	.63	2.51
2014	.91	.58	.56	.55	2.60
2015	.78	.59	.68	.65	2.70

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.20	.20	.20	.20	.80
2011	.26	.26	.26	.26	1.04
2012	.30	.30	.30	.30	1.20
2013	.34	.34	.3825	.3825	1.45
2014	.39	.39	.39	.39	

BUSINESS: Wisconsin Energy Corporation is a holding company for We Energies, which provides electric, gas & steam service in Wisconsin. Customers: 1.1 mill. elec., 1.1 mill. gas. Acq'd WICOR 4/00. Discontinued pump-manufacturing operations in '04. Sold Point Beach nuclear plant in '07. Elec. revenue breakdown: residential, 36%; small commercial & industrial, 32%; large commercial & industrial, 22%; other, 10%. Generating sources: coal, 54%; gas, 10%; renewables, 3%; purchased, 33%. Fuel costs: 40% of revs. '13 reported deprec. rate (utility): 2.9%. Has 4,300 employees. Chairman & CEO: Gale E. Klappa. President: Allen L. Leverett. Inc.: WI. Address: 231 W. Michigan St., P.O. Box 1331, Milwaukee, WI 53201. Tel.: 414-221-2345. Internet: www.wisconsinenergy.com.

The takeover of Integrys Energy by Wisconsin Energy has been approved by each company's shareholders. Under the agreement, Wisconsin Energy would buy Integrys for $4.6 billion in common stock and $1.5 billion in cash (to be financed with debt). Integrys would be a good fit, since it provides electric and gas service in Wisconsin, and would expand the service area to Illinois. (Integrys also serves parts of Michigan and Minnesota.) The transaction requires the approval of the regulatory commissions in Wisconsin, Illinois, and Michigan (and perhaps Minnesota, also), plus the Federal Energy Regulatory Commission. The companies expect the deal to be completed in the second half of 2015. Wisconsin Energy would then change its name to WEC Energy.

Management believes that the acquisition would enhance the company's growth rate. Wisconsin Energy's current goal is 4%-6% annually, and the combination with Integrys would boost this target to 5%-7%. Wisconsin Energy's free cash flow would be used to fund some of Integrys' capital projects.

Shareholders can look forward to a hefty dividend hike in early 2015. Wisconsin Energy has signaled that it plans to raise the annual payout by $0.11 a share (8.3%), subject to approval by the board of directors. Shareholders can expect another increase when the Integrys deal closes.

We estimate 4% earnings growth in 2014 and 2015. Note that our figures exclude Integrys, but include merger-related expenses, which are estimated at $0.05 a share this year.

The company should soon get an order in its general rate case. Some issues have been settled. A nonfuel electric rate hike of $41.5 million will take effect in January, and Wisconsin Electric and Wisconsin Gas will have allowed returns on equity of 10.2% and 10.3%, respectively. Still to be determined is what the fuel-cost recovery will be in 2015.

High-quality Wisconsin Energy stock offers a respectable yield and good 3- to 5-year dividend growth potential. The recent price is above the upper end of our 2017-2019 Target Price Range, but if the Integrys deal goes through, our projections might well prove conservative.

Paul E. Debbas, CFA *December 19, 2014*

(A) Diluted EPS. Excl. nonrec. gains (losses): '99, (5¢); '00, 10¢ net; '02, (44¢); '03, (10¢) net; '04, (42¢); gains on disc. ops.: '04, 77¢; '05, 2¢; '06, 2¢; '09, 2¢; '10, 1¢; '11, 6¢. '11 EPS don't add due to rounding. Next earnings report due early Feb. (B) Div'ds historically paid in early Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '13: $6.86/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in WI in '13: 10.4%-10.5%; earned on avg. com. eq., '13: 13.6%. Regulat. Climate: Above Avg.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	100

Staff/209
Muldoon/47

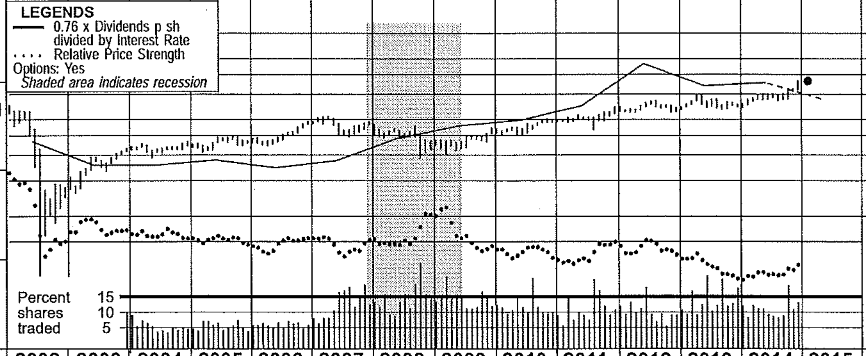
XCEL ENERGY NYSE-XEL

RECENT PRICE 37.27 | P/E RATIO 18.8 (Trailing: 19.2, Median: 14.0) | RELATIVE P/E RATIO 1.02 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 Raised 12/27/13
SAFETY 2 Raised 5/14/04
TECHNICAL 3 Lowered 1/30/15
BETA .65 (1.00 = Market)

High:	17.4	18.8	20.2	23.6	25.0	22.9	21.9	24.4	27.8	29.9	31.8	37.6
Low:	10.4	15.5	16.5	17.8	19.6	15.3	16.0	19.8	21.2	25.8	26.8	27.3

Target Price Range 2017 | 2018 | 2019



64 48 40 32 24 20 16 12 8 6

2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(-5%)	2%
Low	25	(-35%)	-5%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	226	239	233
to Sell	212	181	189
Hld's(000)	342517	351983	351672

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	33.5	6.9
3 yr.	43.1	73.7
5 yr.	100.7	107.3

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
18.46	18.42	34.11	43.56	23.89	19.90	20.84	23.86	24.16	23.40	24.69	21.08	21.38	21.90	20.76	21.92	22.85	23.60	Revenues per sh	26.25
4.30	4.13	4.12	5.09	3.14	3.35	3.27	3.28	3.61	3.45	3.50	3.48	3.51	3.79	4.00	4.10	4.20	4.60	"Cash Flow" per sh	5.25
1.84	1.43	1.60	2.27	.42	1.23	1.27	1.20	1.35	1.35	1.46	1.49	1.56	1.72	1.85	1.91	1.95	2.05	Earnings per sh A	2.50
1.43	1.45	1.48	1.50	1.13	.75	.81	.85	.88	.91	.94	.97	1.00	1.03	1.07	1.11	1.20	1.26	Div'd Decl'd per sh B ■	1.45
2.99	13.87	3.63	7.40	6.04	2.49	3.19	3.25	4.00	4.89	4.66	3.91	4.60	4.53	5.27	6.82	5.70	6.65	Cap'l Spending per sh	5.25
16.25	16.42	16.37	17.95	11.70	12.95	12.99	13.37	14.28	14.70	15.35	15.92	16.76	17.44	18.19	19.21	20.05	20.90	Book Value per sh C	24.00
152.70	155.73	339.79	345.02	398.71	398.96	400.46	403.39	407.30	428.78	453.79	457.51	482.33	486.49	487.96	497.97	506.00	508.00	Common Shs Outst'g D	514.00
15.2	16.6	14.3	12.4	NMF	11.6	13.6	15.4	14.8	16.7	13.7	12.7	14.1	14.2	14.8	15.0	16.1		Avg Ann'l P/E Ratio	12.5
.79	.95	.93	.64	NMF	.66	.72	.82	.80	.89	.82	.85	.90	.89	.94	.84	.85		Relative P/E Ratio	.80
5.1%	6.1%	6.4%	5.3%	6.6%	5.2%	4.7%	4.6%	4.4%	4.0%	4.7%	5.1%	4.5%	4.2%	3.9%	3.9%	3.8%		Avg Ann'l Div'd Yield	4.7%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $12456 mill. **Due in 5 Yrs** $3564.6 mill.
LT Debt $11502 mill. **LT Interest** $551.8 mill.
Incl. $179.4 mill. capitalized leases.
(LT interest earned: 3.5x)

Leases, Uncapitalized Annual rentals $240.7 mill.
Pension Assets-12/13 $3010.1 mill.
Oblig. $3440.7 mill.
Pfd Stock None

Common Stock 505,685,923 shs.
as of 10/24/14
MARKET CAP: $19 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
8345.3	9625.5	9840.3	10034	11203	9644.3	10311	10655	10128	10915	11550	12000	Revenues ($mill)	13500
526.9	499.0	568.7	575.9	645.7	685.5	727.0	841.4	905.2	948.2	985	1045	Net Profit ($mill)	1260
23.2%	25.8%	24.2%	33.8%	34.4%	35.1%	37.5%	35.8%	33.2%	33.8%	35.0%	35.0%	Income Tax Rate	35.0%
10.9%	8.5%	9.8%	12.5%	15.9%	16.8%	11.7%	9.4%	10.8%	13.4%	14.0%	10.0%	AFUDC % to Net Profit	10.0%
55.0%	51.7%	52.1%	49.7%	52.2%	51.6%	53.1%	51.1%	53.3%	53.3%	53.0%	53.5%	Long-Term Debt Ratio	52.5%
44.1%	47.3%	47.0%	49.4%	47.1%	47.7%	46.3%	48.9%	46.7%	46.7%	47.0%	46.5%	Common Equity Ratio	47.5%
11801	11398	12371	12748	14800	15277	17452	17331	19018	20477	21650	22975	Total Capital ($mill)	25800
14096	14696	15549	16676	17689	18508	20663	22353	23809	26122	27875	29950	Net Plant ($mill)	34000
6.2%	6.2%	6.2%	6.3%	6.0%	6.2%	5.7%	6.5%	6.1%	6.0%	6.0%	6.0%	Return on Total Cap'l	6.0%
9.9%	9.1%	9.6%	9.0%	9.1%	9.3%	8.9%	9.9%	10.2%	9.9%	9.5%	10.0%	Return on Shr. Equity	10.0%
10.0%	9.2%	9.7%	9.1%	9.2%	9.4%	8.9%	9.9%	10.2%	9.9%	9.5%	10.0%	Return on Com Equity E	10.0%
3.9%	2.9%	3.6%	3.1%	3.8%	3.7%	3.6%	4.3%	4.7%	4.5%	4.0%	4.0%	Retained to Com Eq	4.0%
62%	69%	63%	66%	59%	61%	59%	56%	54%	54%	61%	61%	All Div'ds to Net Prof	59%

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+.4	-.3	+.3
Large C & I Use (MWH)	24286	24074	23875
Large C & I Revs. per KWH (¢)	5.90	5.60	6.23
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	21898	21429	21258
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.4	+.7	+.8
Fixed Charge Cov. (%)	298	303	321

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-3.0%	-2.0%	3.5%
"Cash Flow"	.5%	2.5%	5.0%
Earnings	3.5%	5.5%	5.5%
Dividends	-.5%	3.5%	5.0%
Book Value	2.5%	4.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	2817	2438	2832	2568	10655
2012	2578	2275	2724	2551	10128
2013	2783	2579	2822	2731	10915
2014	3203	2685	2870	2792	11550
2015	3200	2750	3100	2950	12000

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.42	.33	.69	.29	1.72
2012	.38	.38	.81	.29	1.85
2013	.48	.40	.73	.30	1.91
2014	.52	.39	.73	.31	1.95
2015	.50	.44	.78	.33	2.05

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.253	.253	.26	.26	1.03
2012	.26	.26	.27	.27	1.06
2013	.27	.27	.28	.28	1.10
2014	.28	.30	.30	.30	1.18
2015	.30				

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power, which supplies electricity to Minnesota, Wisconsin, North Dakota, South Dakota & Michigan & gas to Minnesota, Wisconsin, North Dakota & Michigan; Public Service of Colorado, which supplies electricity & gas to Colorado; & Southwestern Public Service, which supplies electricity to Texas & New Mexico. Customers: 3.5 mill. electric, 1.9 mill. gas. Elec. rev. breakdown: residential, 32%; sm. comm'l & ind'l, 36%; lg. comm'l & ind'l, 19%; other, 13%. Generating sources not available. Fuel costs: 47% of revs. '13 reported depr. rate: 2.9%. Has 11,600 employees. Chairman, Pres. & CEO: Ben Fowke. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

Xcel Energy's utility subsidiary in Minnesota is awaiting an order on its multiyear rate application. Northern States Power (NSP) is seeking rate hikes of $142.2 million for 2014 and $106.0 million for 2015, based on a return of 10.25% on a 52.5% common-equity ratio. (NSP is now collecting an interim tariff hike of $127 million.) An administrative law judge has recommended increases of $73.6 million in 2014 and $122.4 million in 2015, based on a 9.77% return on a 52.5% common-equity ratio. The commission's order is expected in the second quarter.

The Minnesota commission is examining the prudence of an uprate and life extension for a nuclear plant. The original estimate of this project was $320 million; the final cost was $665 million. If any portion of this spending is disallowed, Xcel would have to take a writedown.

The company is seeking electric rate hikes in other states. Public Service of Colorado is asking for an electric increase of $107.2 million, based on a return of 10.25% on a common-equity ratio of 56%. On the other hand, the commission's staff and Office of Consumer Counsel are proposing rate *decreases*. NSP filed for $15.6 million in South Dakota, based on a 10.25% return on a 53.86% common-equity ratio. Southwestern Public Service asked the Texas commission for a $64.8 million boost, based on a 10.25% return on a 53.97% common-equity ratio. Orders on each of these filings are expected in 2015.

The company received electric rate hikes in Wisconsin and Texas. NSP was granted $14.2 million in Wisconsin and $37.0 million in Texas.

Rate relief is a significant driver of Xcel's profit growth. Our 2015 earnings estimate of $2.05 a share is within the company's targeted range of $2.00-$2.15 a share.

We look for a dividend increase this quarter. We estimate that the annual payout will be raised $0.06 a share (5%), which is within Xcel's dividend growth goal of 4%-6% a year.

The dividend yield of Xcel stock is about average for a utility. Like several other utility issues, the recent price is above our 2017-2019 Target Price Range, so total return potential is negative.

Paul E. Debbas, CFA *January 30, 2015*

(A) Diluted EPS. Excl. nonrec. gain (loss): '02, ($6.27); '10, 5¢; gains (losses) on disc. ops.: '03, 27¢; '04, (30¢); '05, 3¢; '06, 1¢; '09, (1¢); '10, 1¢. '11 & '12 EPS don't add due to rounding. Next egs. report due late Apr. **(B)** Div'ds histor. paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. **(C)** Incl. intang. In '13: $5.04/sh. **(D)** In mill. **(E)** Rate base: Varies. Rate all'd on com. eq.: MN '13 9.83%; WI '15 10.2%; CO '14 (elec.) 9.72%; CO '07 (gas) 10.25%; TX '14 10.4%; earned on avg. com. eq., '13: 10.3%. Regulatory Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	100

CASE: UE 294
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 210

Moody's Investor Services
Sector In-Depth – U.S. Regulated Utilities

Exhibits in Support
of Opening Testimony

June 15, 2015

MOODY'S
INVESTORS SERVICE

SECTOR IN-DEPTH
10 MARCH 2015

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US Regulated Utilities

Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles

The credit profiles of US regulated utilities will remain intact over the next few years despite our expectation that regulators will continue to trim the sector's profitability by lowering its authorized returns on equity (ROE). Persistently low interest rates and a comprehensive suite of cost recovery mechanisms ensure a low business risk profile for utilities, prompting regulators to scrutinise their profitability, which is defined as the ratio of net income to book equity. We view cash flow measures as a more important rating driver than authorized ROEs, and we note that regulators can lower authorized ROEs without hurting cash flow, for instance by targeting depreciation, or through special rate structures. Regulators can also adjust a utility's equity capitalization in its rate base. All else being equal, we think most utilities would prefer a thicker equity base and a lower authorized ROE over a small equity layer and a high authorized ROE.

» **More timely cost recovery helps offset falling ROEs**. Regulators continue to permit a robust suite of mechanisms that enable utilities to recoup prudently incurred operating costs, including capital investments such as environment related or infrastructure hardening expenditures. Strong cost recovery is credit positive because it ensures a stable financial profile. Despite lower authorized ROEs, we see the sector maintaining a ratio of Funds From Operations (FFO) to debt near 20%, a level that continues to support strong investment-grade ratings.

» **Utilities' cash flow is somewhat insulated from lower ROEs**. Net income represents about 30% - 40% of utilities' cash flow, so lower authorized returns won't necessarily affect cash flow or key financial credit ratios, especially when the denominator (equity) is rising. Regulators set the equity layer when capitalizing rate base, and the equity layer multiplied by the authorized ROE drives the annual revenue requirements. Across the sector, the ratio of equity to total assets has remained flat in the 30% range since 2007.

» **Utilities' actual financial performance remains stable**. Earned ROEs, which typically lag authorized ROEs, have not fallen as much as authorized returns in recent years. Since 2007, vertically integrated utilities, transmission and distribution only utilities, and natural gas local distribution companies have maintained steady earned ROE's in the 9% - 10% range. Holding companies with primarily regulated businesses also earned ROEs of around 9% - 10%, while returns for holding companies with diversified operations, namely unregulated generation, have fallen from 11% (over the past seven year average) to around 9% today.

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Muldoon/2

Robust Suite of Cost Recovery Mechanisms Is Credit Positive

Over the past few years, the US regulatory environment has been very supportive of utilities. We think this is partly because regulators acknowledge that utility infrastructure needs a material amount of ongoing investment for maintenance, refurbishment and renovation. Utilities have also been able to garner support from both politicians and regulators for prudent investment in these critical assets because it helps create jobs, spurring economic growth. We also think regulators prefer to regulate financially healthy utilities.

Across the US, we continue to see regulators approving mechanisms that allow for more timely recovery of costs, a material credit positive. These mechanisms, which keep utilities' business risk profile low compared to most industrial corporate sectors, include: formulaic rate structures; special purpose trackers or riders; decoupling programs (which delink volumes from revenue); the use of future test years or other pre-approval arrangements. We also see a sustained increase in the frequency of rate case filings.

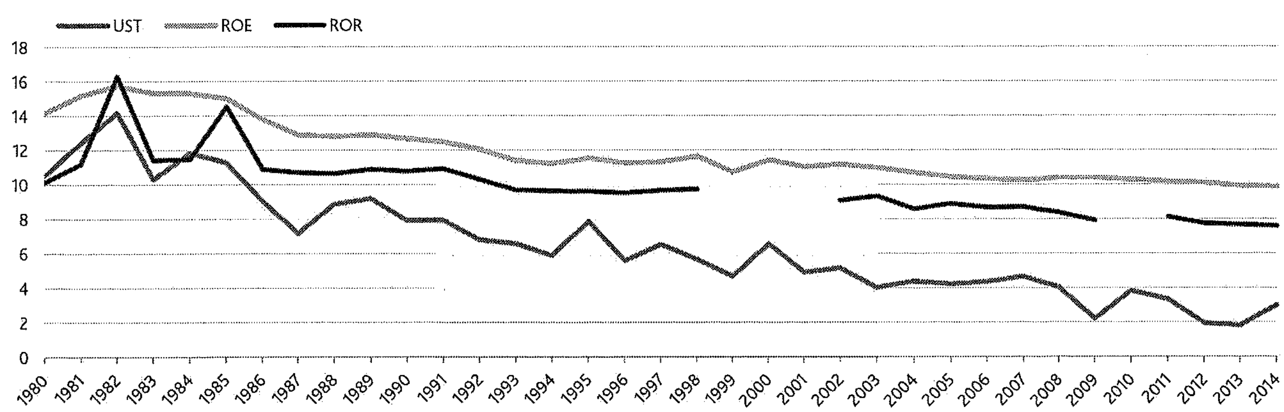
A supportive regulatory environment translates into a more transparent and stable financial profile, which in turn results in reasonably unfettered access to capital markets - for both debt and equity. Today, we think utilities enjoy an attractive set of market conditions that will remain in place over the next few years. By themselves, neither a slow (but steady) decline in authorized profitability, nor a material revision in equity market valuation multiples, will derail the stable credit profile of US regulated utilities.

Cost recovery will help offset falling ROEs

Robust cost recovery mechanisms will help ensure that US regulated utilities' credit quality remains intact over the next few years. As a result, falling authorized ROEs are not a material credit driver at this time, but rather reflect regulators' struggle to justify the cost of capital gap between the industry's authorized ROEs and persistently low interest rates. We also see utilities struggling to defend this gap, while at the same time recovering the vast majority of their costs and investments through a variety of rate mechanisms.

In the table below, we show the US Treasury 10-year yield, which has steadily fallen from the 5% range in the summer of 2007 to the 2% range today. US utilities benefit from these lower interest rates because they borrow approximately $50 billion a year. For some utilities, a lower cost of debt translates directly into a higher return on equity, as long as their rate structure includes an embedded weighted average cost of capital (and the utilities can stay out of a general rate case proceeding).

Exhibit 1
Regulators hold up their end of the bargain by limiting reduction in return on equity (ROE) and overall rate of return (ROR) when compared with the decline in US Treasury 10-year yields



SOURCE: SNL Financial, LP, Moody's

Staff/210
Muldoon/3

As utilities increasingly secure more up-front assurance for cost recovery in their rate proceedings, we think regulators will increasingly view the sector as less risky. The combination of low capital costs, high equity market valuation multiples (which are better than or on par with the broader market despite the regulated utilities' low risk profile), and a transparent assurance of cost recovery tend to support the case for lower authorized returns, although because utilities will argue they should rise, or at least stay unchanged.

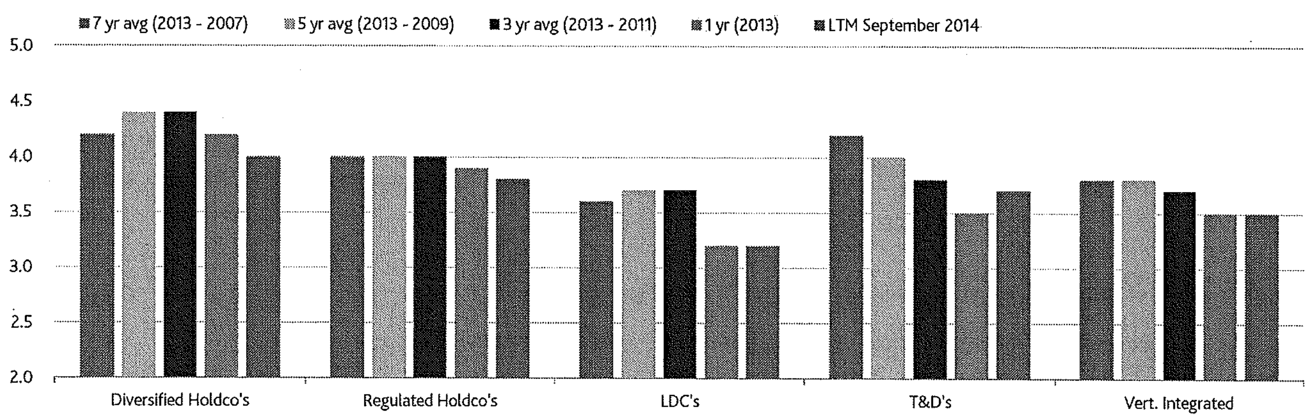
One of the arguments for keeping authorized ROEs steady is that lowering them would make utilities less attractive to providers of capital. Utility holding companies assert that they would rather invest in higher risk-adjusted opportunities than in a regulated utility with sub-par return prospects. We see a risk that this argument could lead to a more contentious regulatory environment, a material credit negative. We do not think this scenario will develop over the next few years.

Our default and recovery data provides strong evidence that regulated utilities are indeed less risky (from the perspective of a probability of default and expected loss given default, as defined by Moody's) than their non-financial corporate peers. On a global basis, we nonetheless see a material amount of capital looking for regulated utility investment opportunities, and the same is true in the US despite, despite a lower authorized return. This is partly because investors can use holding company leverage to increase their actual equity returns, by borrowing capital at today's low interest rates and investing in the equity of a regulated utility.

Despite the reduction in authorized ROEs, US utilities are thankful to their regulators for the robust suite of timely cost recovery mechanisms which allow them to recoup prudently incurred operating costs such as fuel, as well as some investment expenses. These recovery mechanisms drive a stable and transparent dividend policy, which translates into historically very high equity multiples. Moreover, cost recovery helps keep the sector's overall financial profile stable, thereby supporting strong investment-grade ratings.

Exhibit 2

With better recovery mechanisms, the ratio of debt-to-EBITDA can rise, modestly, without negatively impacting credit profiles



SOURCE: Company filings; Moody's

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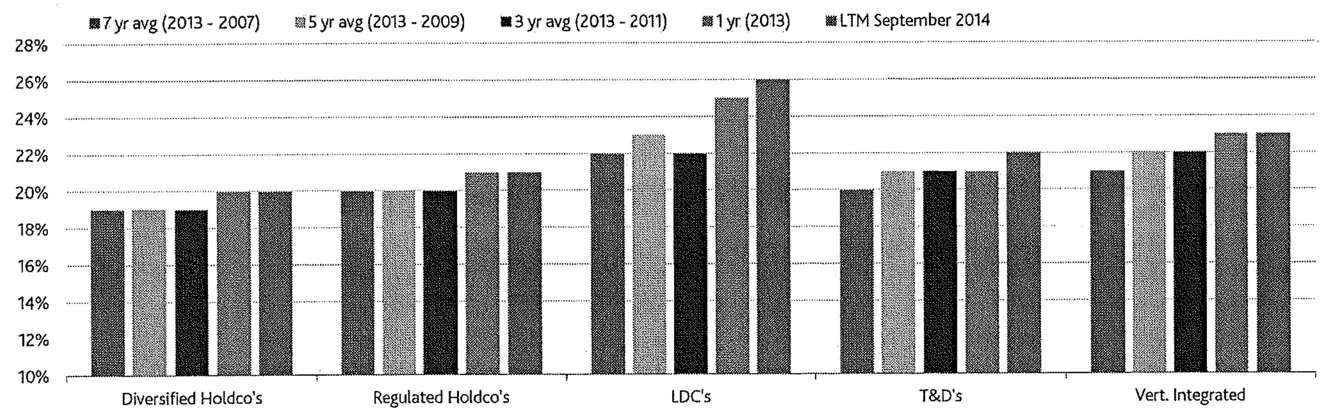
Muldoon/4

Exhibit 3
The ratio of Funds From Operations to debt is rising, a material credit positive,
but the rise is partly funded by bonus depreciation and deferred taxes, which will eventually reverse



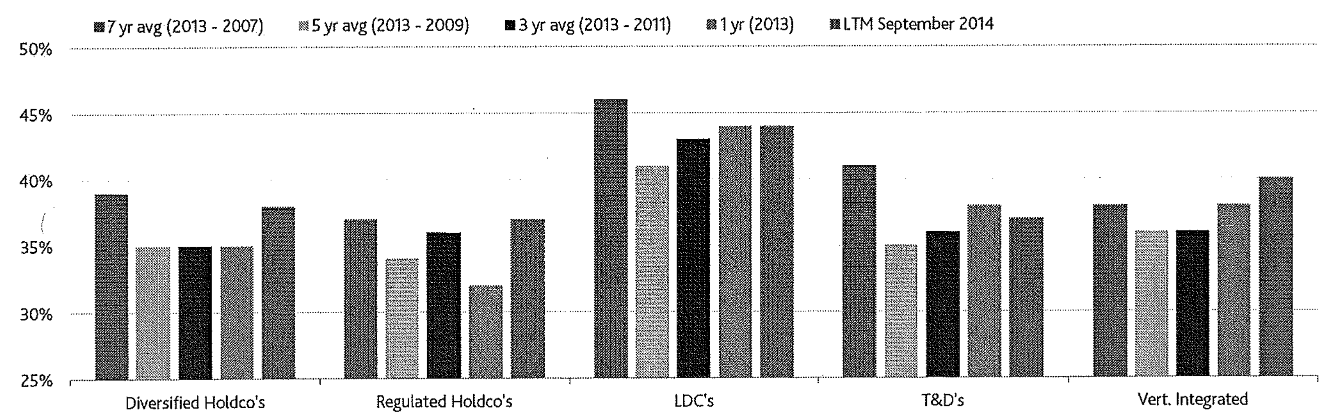
SOURCE: Company filings; Moody's

Utilities' cash flow is somewhat insulated from declining ROEs

Across all our utility group sub-sectors (see Appendix), net income - the numerator in the calculation of ROE – accounts for between 30% - 40% of cash flow. While net income is important, cash flow exerts a much greater influence over creditworthiness. This is primarily because cash flow takes into account depreciation and amortization expenses, along with other deferred tax adjustments. We note that deferred taxes have risen over the past few years, in part due to bonus depreciation elections, which will eventually reverse. From a credit perspective, there is a difference between the nominal amount of net income, which goes into cash flow, and the relationship of net income to book equity (a measure of profitability).

In the chart below, we highlight the ratio of net income to cash flow from operations (CFO) for our selected peer groups. Across all of the sectors, the longer term historical average of net income to CFO has fallen compared with the late 2000s, but has been rising over the more recent past. This is partly a function of deferred taxes, which have become a larger component of CFO over the past decade.

Exhibit 4
Net income as a % of cash flow from operations has been steadily rising (since 2011)



SOURCE: Company filings, Moody's

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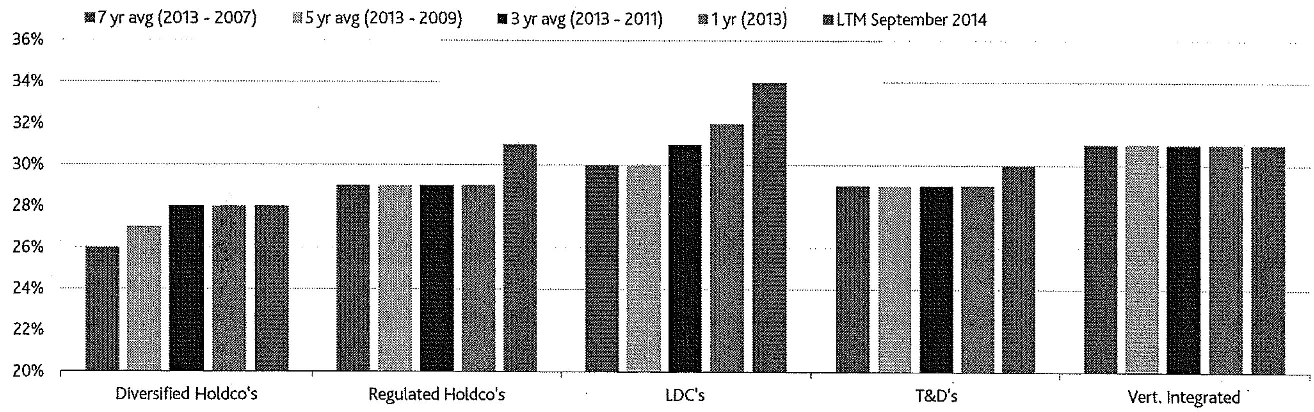
Muldoon/5

We can also envisage scenarios where regulators seek to achieve a reduction in authorized ROEs without harming credit profiles by focusing on utilities' equity layer. In the chart below, we illustrate median equity as a percentage of total assets for our selected peer groups. In our illustration, utilities will benefit from acquisition related goodwill on one hand, and impairments on the other.

Exhibit 5

Equity as a % of total assets, not capitalization, includes both goodwill and impairments



SOURCE: Company filings; Moody's

Utilities' actual financial performance remains stable

Earned ROE's, as reported by utilities and adjusted by Moody's, have been relatively flat over the past few years, despite the decline in authorized ROEs. This means utilities are closer to earning their authorized equity returns, which is positive from an equity market valuation perspective.

The authorized ROE is a popular focal point in many regulatory rate case proceedings. In addition, many regulatory jurisdictions look to established precedents that rely on various methodologies to determine an appropriate ROE, such as the capital asset pricing model or discounted cash flow analysis. In some jurisdictions where formulaic based rate structures point to lower ROEs for a longer projected period of time, regulators are incorporating a view that today's interest rate environment is "artificially" being held low.

Regardless, we think interest rates will go up, eventually. When they do, we also think authorized ROEs will trend up as well. However, just as authorized ROEs declined in a lagging fashion when compared to falling interest rates, we expect authorized ROEs to rise in a lagging fashion when interest rates rise.

Depending on alternative sources of risk-adjusted capital investment opportunities, this could spell trouble for utilities. For now, utilities can enjoy their (historically) high equity valuations, in terms of dividend yield and price-earnings ratios.

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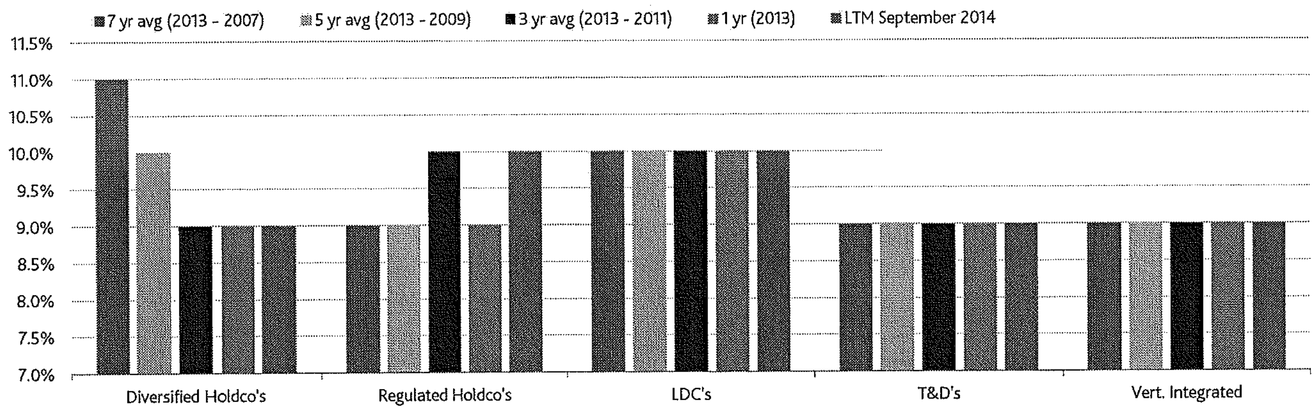
Muldoon/6

Exhibit 6

GAAP adjusted earned ROE's are relatively flat across all sub-sectors except Holding Companies with Diversified Operations, while the lower-risk LDC sector is outperforming



NOTE: GAAP adjusted ROE, not regulated ROE, does not adjust for goodwill or impairments.

Source: Company filings; Moody's

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Appendix

Exhibit 7
Utilities with the highest earned ROEs (ranked by 7-year average)

Company Name	Sector	Rating	1-year average (2013) ROE	3-year average (2013 - 2011) ROE	5-year average (2013 - 2009) ROE	7-year average (2013 - 2007) ROE
CenterPoint Energy Houston Electric, LLC	T&D	A3	33%	32%	25%	23%
Questar Corporation	Holdco - Primarily Regulated	A2	14%	18%	20%	20%
AEP Texas Central Company	T&D	Baa1	14%	28%	22%	20%
Exelon Corporation	Holdco - Diversified	Baa2	7%	10%	14%	17%
CenterPoint Energy, Inc.	Holdco - Primarily Regulated	Baa1	7%	16%	15%	17%
Ohio Edison Company	T&D	Baa1	23%	18%	17%	16%
Public Service Enterprise Group	Holdco - Diversified	Baa2	11%	12%	14%	15%
Dayton Power & Light Company	T&D	Baa3	7%	9%	13%	15%
Dominion Resources Inc.	Holdco - Diversified	Baa2	13%	9%	12%	15%
Southern California Gas Company	LDC	A1	14%	13%	14%	15%
PECO Energy Company	T&D	A2	12%	12%	12%	14%
PPL Corporation	Holdco - Diversified	Baa3	9%	12%	11%	14%
UGI Utilities, Inc.	LDC	A2	15%	13%	13%	13%
Entergy Corporation	Holdco - Diversified	Baa3	7%	11%	12%	13%
Cleco Corporation	Holdco - Primarily Regulated	Baa1	10%	12%	13%	13%
Alabama Gas Corporation	LDC	A2	4%	11%	12%	13%
Entergy New Orleans, Inc.	Vertically Integrated Utility	Ba2	5%	10%	11%	12%
Entergy Gulf States Louisiana, LLC	Vertically Integrated Utility	Baa1	11%	13%	12%	12%
Piedmont Natural Gas Company, Inc.	LDC	A2	11%	11%	12%	12%
Ohio Power Company	T&D	Baa1	25%	14%	13%	12%
Southern Company (The)	Holdco - Primarily Regulated	Baa1	9%	11%	11%	12%
Georgia Power Company	Vertically Integrated Utility	A3	12%	12%	12%	12%
Alabama Power Company	Vertically Integrated Utility	A1	12%	12%	12%	12%
Southern California Edison Company	Vertically Integrated Utility	A2	8%	12%	12%	12%
NextEra Energy, Inc.	Holdco - Diversified	Baa1	10%	11%	11%	12%
Wisconsin Energy Corporation	Holdco - Primarily Regulated	A2	13%	13%	12%	12%
West Penn Power Company	T&D	Baa1	17%	13%	12%	12%
San Diego Gas & Electric Company	Vertically Integrated Utility	A1	9%	10%	11%	12%
Interstate Power and Light Company	Vertically Integrated Utility	A3	10%	9%	9%	12%

NOTE: GAAP adjusted ROE, not regulated ROE, does not adjust for goodwill or impairments.

SOURCE: Moody's; company filings

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Exhibit 8

Highest (over 30%) and lowest (less than 20%) equity level as a % of total assets (ranked by 7-year average) [NOTE: Book equity is not adjusted for goodwill or impairments]

Company Name	Sector	Rating	1-year average (2013)	3-year average (2013 - 2011)	5-year average (2013 - 2009)	7-year average (2013 - 2007)
Duke Energy Ohio, Inc.	T&D	Baa1	48%	47%	48%	50%
Yankee Gas Services Company	LDC	Baa1	41%	42%	43%	43%
Texas-New Mexico Power Company	T&D	Baa1	43%	43%	43%	43%
Oncor Electric Delivery Company LLC	T&D	Baa1	40%	41%	41%	43%
Dayton Power & Light Company	T&D	Baa3	37%	38%	39%	40%
Pennsylvania Power Company	T&D	Baa1	25%	30%	34%	40%
Black Hills Power, Inc.	Vertically Integrated Utility	A3	38%	38%	37%	38%
ALLETE, Inc.	Vertically Integrated Utility	A3	38%	37%	37%	38%
Central Maine Power Company	T&D	A3	39%	38%	38%	38%
MGE Energy, Inc.	Holdco - Primarily Regulated	NR	39%	37%	38%	38%
Duke Energy Corporation	Holdco - Primarily Regulated	A3	36%	36%	37%	38%
Jersey Central Power & Light Company	T&D	Baa2	32%	33%	36%	38%
Oklahoma Gas & Electric Company	Vertically Integrated Utility	A1	36%	37%	37%	37%
Public Service Company of Colorado	Vertically Integrated Utility	A3	37%	37%	37%	37%
Virginia Electric and Power Company	Vertically Integrated Utility	A2	37%	37%	37%	35%
Wisconsin Public Service Corporation	Vertically Integrated Utility	A1	34%	34%	34%	35%
PacifiCorp	Vertically Integrated Utility	A3	36%	35%	35%	35%
UGI Utilities, Inc.	LDC	A2	35%	34%	34%	34%
Cleco Corporation	Holdco - Primarily Regulated	Baa1	37%	36%	34%	34%
Empire District Electric Company (The)	Vertically Integrated Utility	Baa1	35%	34%	34%	34%
Great Plains Energy Incorporated	Holdco - Primarily Regulated	Baa2	35%	35%	34%	34%
Nevada Power Company	Vertically Integrated Utility	Baa1	32%	33%	33%	33%
Tampa Electric Company	Vertically Integrated Utility	A2	34%	33%	33%	33%
Wisconsin Power and Light Company	Vertically Integrated Utility	A1	34%	33%	32%	33%
Questar Corporation	Holdco - Primarily Regulated	A2	29%	28%	31%	33%
Duke Energy Kentucky, Inc.	Vertically Integrated Utility	Baa1	31%	30%	33%	33%
Florida Power & Light Company	Vertically Integrated Utility	A1	36%	35%	34%	33%
Alabama Gas Corporation	LDC	A2	59%	40%	35%	33%
El Paso Electric Company	Vertically Integrated Utility	Baa1	34%	32%	32%	33%
IDACORP, Inc.	Holdco - Primarily Regulated	Baa1	34%	33%	33%	33%
PPL Electric Utilities Corporation	Vertically Integrated Utility	Baa1	34%	34%	34%	33%
Commonwealth Edison Company	T&D	Baa1	31%	32%	32%	33%
Georgia Power Company	Vertically Integrated Utility	A3	33%	33%	33%	33%
CMS Energy Corporation	Holdco - Primarily Regulated	Baa2	20%	19%	18%	18%
Hawaiian Electric Industries, Inc.	Holdco - Diversified		17%	16%	16%	16%
CenterPoint Energy, Inc.	Holdco - Primarily Regulated	Baa1	20%	19%	17%	15%
CenterPoint Energy Houston Electric, LLC	T&D	A3	9%	15%	15%	15%
AEP Texas Central Company	T&D	Baa1	13%	15%	14%	13%

SOURCE: Moody's; company filings

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Exhibit 9

Highest (over 30%) and lowest (less than 15%) ratio of FFO to debt (ranked by 7-year average)

Company Name	Sector	Rating	1-year average (2013)	3-year average (2013 - 2011)	5-year average (2013 - 2009)	7-year average (2013 - 2007)
Dayton Power & Light Company	T&D	Baa3	32%	34%	42%	42%
Questar Corporation	Holdco - Primarily Regulated	A2	29%	30%	31%	42%
Pennsylvania Power Company	T&D	Baa1	30%	34%	32%	37%
Exelon Corporation	Holdco - Diversified	Baa2	28%	34%	37%	37%
Alabama Gas Corporation	LDC	A2	23%	27%	32%	36%
Florida Power & Light Company	Vertically Integrated Utility	A1	34%	35%	35%	35%
Southern California Gas Company	LDC	A1	42%	37%	35%	34%
Southern California Edison Company	Vertically Integrated Utility	A2	32%	33%	35%	32%
Madison Gas and Electric Company	Vertically Integrated Utility	A1	39%	35%	34%	31%
PECO Energy Company	T&D	A2	29%	31%	33%	31%
Dominion Resources Inc.	Holdco - Diversified	Baa2	16%	17%	16%	14%
Entergy Texas, Inc.	Vertically Integrated Utility	Baa3	15%	14%	12%	14%
Monongahela Power Company	T&D	Baa2	13%	16%	15%	14%
CMS Energy Corporation	Holdco - Primarily Regulated	Baa2	18%	16%	15%	14%
Appalachian Power Company	Vertically Integrated Utility	Baa1	15%	13%	14%	14%
Pennsylvania Electric Company	T&D	Baa2	15%	14%	12%	13%
NiSource Inc.	Holdco - Diversified	Baa2	15%	14%	14%	13%
Puget Energy, Inc.	Vertically Integrated Utility	Baa3	14%	12%	12%	13%
Toledo Edison Company	T&D	Baa3	10%	10%	8%	13%
Cleveland Electric Illuminating Company	T&D	Baa3	11%	11%	12%	13%
AEP Texas Central Company	T&D	Baa1	14%	15%	13%	12%

SOURCE: Moody's; company filings

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Exhibit 10

Highest (over 4.5x) and lowest (less than 3.0x) ratio of debt to EBITDA (ranked by 1-year average, 2013, to focus on more recent performance)

Company Name	Sector	Rating	1-year average (2013)	3-year average (2013 - 2011)	5-year average (2013 - 2009)	7-year average (2013 - 2007)
Berkshire Hathaway Energy Company	Holdco - Diversified	A3	7.1	5.8	5.6	5.3
FirstEnergy Corp.	Holdco - Diversified	Baa3	6.0	5.2	4.8	4.4
Wisconsin Electric Power Company	Vertically Integrated Utility	A1	5.9	6.1	5.6	5.0
Entergy Texas, Inc.	Vertically Integrated Utility	Baa3	5.8	6.1	6.2	6.1
Monongahela Power Company	T&D	Baa2	5.6	5.2	5.7	6.0
NiSource Inc.	Holdco - Diversified	Baa2	5.2	5.5	5.4	5.5
PPL Corporation	Holdco - Diversified	Baa3	5.1	4.9	5.1	4.6
Appalachian Power Company	Vertically Integrated Utility	Baa1	5.0	5.0	5.2	5.4
Progress Energy, Inc.	Holdco - Primarily Regulated	Baa1	4.9	5.6	5.1	4.9
Puget Energy, Inc.	Vertically Integrated Utility	Baa3	4.9	5.6	5.9	5.6
Cleveland Electric Illuminating Company	T&D	Baa3	4.9	5.2	4.7	4.2
Northwest Natural Gas Company	LDC	A3	4.8	4.8	4.5	4.2
Jersey Central Power & Light Company	T&D	Baa2	4.7	5.5	4.2	3.6
NorthWestern Corporation	Vertically Integrated Utility	A3	4.7	4.5	4.4	4.3
Pepco Holdings, Inc.	Holdco - Primarily Regulated	Baa3	4.7	5.1	5.2	5.2
Laclede Gas Company	LDC	A3	4.7	5.5	5.3	5.6
Atlantic City Electric Company	T&D	Baa2	4.7	4.9	4.8	4.7
Nevada Power Company	Vertically Integrated Utility	Baa1	4.6	4.6	4.9	5.0
Black Hills Power, Inc.	Vertically Integrated Utility	A3	2.9	3.2	3.8	3.6
Virginia Electric and Power Company	Vertically Integrated Utility	A2	2.9	3.1	3.4	3.4
Duke Energy Kentucky, Inc.	Vertically Integrated Utility	Baa1	2.9	3.3	3.3	3.4
Texas-New Mexico Power Company	T&D	Baa1	2.9	2.9	3.2	3.3
Oklahoma Gas & Electric Company	Vertically Integrated Utility	A1	2.9	2.9	2.9	3.0
Cleco Power LLC	Vertically Integrated Utility	A3	2.9	3.2	3.6	3.7
Consumers Energy Company	Vertically Integrated Utility	A1	2.9	3.1	3.3	3.5
Alabama Power Company	Vertically Integrated Utility	A1	2.8	2.9	3.0	3.1
Public Service Electric and Gas Company	T&D	A2	2.8	3.0	3.2	3.3
Alabama Gas Corporation	LDC	A2	2.8	2.7	2.5	2.4
Pinnacle West Capital Corporation	Holdco - Primarily Regulated	Baa1	2.8	3.1	3.3	3.6
Cleco Corporation	Holdco - Primarily Regulated	Baa1	2.8	2.9	3.4	3.6
PECO Energy Company	T&D	A2	2.8	3.0	2.6	2.6
Northern States Power Company (Wisconsin)	Vertically Integrated Utility	A2	2.8	2.9	2.8	2.8
Duke Energy Carolinas, LLC	Vertically Integrated Utility	A1	2.8	3.1	3.2	3.1
UGI Utilities, Inc.	LDC	A2	2.7	3.0	3.1	3.3
Exelon Corporation	Holdco - Diversified	Baa2	2.7	2.8	2.5	2.5
West Penn Power Company	T&D	Baa1	2.7	3.3	3.3	3.4
Questar Corporation	Holdco - Primarily Regulated	A2	2.7	2.8	2.7	2.3
Tampa Electric Company	Vertically Integrated Utility	A2	2.6	2.7	2.8	2.9
Arizona Public Service Company	Vertically Integrated Utility	A3	2.6	2.9	3.1	3.3
New York State Electric and Gas Corporation	T&D	A3	2.6	2.9	3.2	4.3
Dayton Power & Light Company	T&D	Baa3	2.5	2.2	2.0	1.9
Florida Power & Light Company	Vertically Integrated Utility	A1	2.4	2.7	2.6	2.6
Ohio Power Company	T&D	Baa1	2.4	2.8	3.1	3.3
Madison Gas and Electric Company	Vertically Integrated Utility	A1	2.4	2.8	2.8	2.9
Pennsylvania Power Company	T&D	Baa1	2.4	2.3	2.4	2.2
MGE Energy, Inc.	Holdco - Primarily Regulated	NR	2.3	2.7	2.9	3.1
Rochester Gas & Electric Corporation	T&D	Baa1	2.3	2.9	3.0	3.5
Public Service Enterprise Group Incorporated	Holdco - Diversified	Baa2	2.3	2.3	2.3	2.4
NSTAR Electric Company	T&D	A2	2.2	2.6	2.7	2.8
Southern California Gas Company	LDC	A1	2.2	2.5	2.4	2.5
Mississippi Power Company	Vertically Integrated Utility	Baa1	(3.2)	3.5	3.4	3.1

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Exhibit 11
List of Companies (NOTE: in our appendix tables, we exclude utilities with private ratings)

Company Name	Sector	Rating
Berkshire Hathaway Energy Company	Holdco - Diversified	A3
Black Hills Corporation	Holdco - Diversified	Baa1
Dominion Resources Inc.	Holdco - Diversified	Baa2
DTE Energy Company	Holdco - Diversified	A3
Entergy Corporation	Holdco - Diversified	Baa3
Exelon Corporation	Holdco - Diversified	Baa2
FirstEnergy Corp.	Holdco - Diversified	Baa3
Hawaiian Electric Industries, Inc.	Holdco - Diversified	NR
Integrys Energy Group, Inc.	Holdco - Diversified	A3
NextEra Energy, Inc.	Holdco - Diversified	Baa1
NiSource Inc.	Holdco - Diversified	Baa2
PPL Corporation	Holdco - Diversified	Baa3
Public Service Enterprise Group Incorporated	Holdco - Diversified	Baa2
Sempra Energy	Holdco - Diversified	Baa1
Alliant Energy Corporation	Holdco - Primarily Regulated	A3
Ameren Corporation	Holdco - Primarily Regulated	Baa2
American Electric Power Company, Inc.	Holdco - Primarily Regulated	Baa1
CenterPoint Energy, Inc.	Holdco - Primarily Regulated	Baa1
Cleco Corporation	Holdco - Primarily Regulated	Baa1
CMS Energy Corporation	Holdco - Primarily Regulated	Baa2
Consolidated Edison, Inc.	Holdco - Primarily Regulated	A3
Duke Energy Corporation	Holdco - Primarily Regulated	A3
Edison International	Holdco - Primarily Regulated	A3
Great Plains Energy Incorporated	Holdco - Primarily Regulated	Baa2
IDACORP, Inc.	Holdco - Primarily Regulated	Baa1
MGE Energy, Inc.	Holdco - Primarily Regulated	NR
Northeast Utilities	Holdco - Primarily Regulated	Baa1
Pepco Holdings, Inc.	Holdco - Primarily Regulated	Baa3
PG&E Corporation	Holdco - Primarily Regulated	Baa1
Pinnacle West Capital Corporation	Holdco - Primarily Regulated	Baa1
PNM Resources, Inc.	Holdco - Primarily Regulated	Baa3
Progress Energy, Inc.	Holdco - Primarily Regulated	Baa1
Questar Corporation	Holdco - Primarily Regulated	A2
SCANA Corporation	Holdco - Primarily Regulated	Baa3
Southern Company (The)	Holdco - Primarily Regulated	Baa1
Wisconsin Energy Corporation	Holdco - Primarily Regulated	A2
Xcel Energy Inc.	Holdco - Primarily Regulated	A3
Alabama Gas Corporation	LDC	A2
Atmos Energy Corporation	LDC	A2
DTE Gas Company	LDC	Aa3
Laclede Gas Company	LDC	A3
New Jersey Natural Gas Company	LDC	Aa2
Northern Natural Gas Company [Private]	LDC	A2
Northwest Natural Gas Company	LDC	A3
Piedmont Natural Gas Company, Inc.	LDC	A2
South Jersey Gas Company	LDC	A2
Southern California Gas Company	LDC	A1
Southwest Gas Corporation	LDC	A3
UGI Utilities, Inc.	LDC	A2
Washington Gas Light Company	LDC	A1
Wisconsin Gas LLC [Private]	LDC	A1
Yankee Gas Services Company	LDC	Baa1
AEP Texas Central Company	T&D	Baa1
AEP Texas North Company	T&D	Baa1
Atlantic City Electric Company	T&D	Baa2

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Baltimore Gas and Electric Company	T&D	A3
CenterPoint Energy Houston Electric, LLC	T&D	A3
Central Hudson Gas & Electric Corporation	T&D	A2
Central Maine Power Company	T&D	A3
Cleveland Electric Illuminating Company (The)	T&D	Baa3
Commonwealth Edison Company	T&D	Baa1
Connecticut Light and Power Company	T&D	Baa1
Consolidated Edison Company of New York, Inc.	T&D	A2
Dayton Power & Light Company	T&D	Baa3
Delmarva Power & Light Company	T&D	Baa1
Duke Energy Ohio, Inc.	T&D	Baa1
Jersey Central Power & Light Company	T&D	Baa2
Metropolitan Edison Company	T&D	Baa1
Monongahela Power Company	T&D	Baa2
New York State Electric and Gas Corporation	T&D	A3
NSTAR Electric Company	T&D	A2
Ohio Edison Company	T&D	Baa1
Ohio Power Company	T&D	Baa1
Oncor Electric Delivery Company LLC	T&D	Baa1
Orange and Rockland Utilities, Inc.	T&D	A3
PECO Energy Company	T&D	A2
Pennsylvania Electric Company	T&D	Baa2
Pennsylvania Power Company	T&D	Baa1
Potomac Edison Company (The)	T&D	Baa2
Potomac Electric Power Company	T&D	Baa1
Public Service Electric and Gas Company	T&D	A2
Rochester Gas & Electric Corporation	T&D	Baa1
Texas-New Mexico Power Company	T&D	Baa1
Toledo Edison Company	T&D	Baa3
West Penn Power Company	T&D	Baa1
Western Massachusetts Electric Company	T&D	A3
Alabama Power Company	Vertically Integrated Utility	A1
ALLETE, Inc.	Vertically Integrated Utility	A3
Appalachian Power Company	Vertically Integrated Utility	Baa1
Arizona Public Service Company	Vertically Integrated Utility	A3
Avista Corp.	Vertically Integrated Utility	Baa1
Black Hills Power, Inc.	Vertically Integrated Utility	A3
Cleco Power LLC	Vertically Integrated Utility	A3
Consumers Energy Company	Vertically Integrated Utility	A1
DTE Electric Company	Vertically Integrated Utility	A2
Duke Energy Carolinas, LLC	Vertically Integrated Utility	A1
Duke Energy Florida, Inc.	Vertically Integrated Utility	A3
Duke Energy Kentucky, Inc.	Vertically Integrated Utility	Baa1
Duke Energy Progress, Inc.	Vertically Integrated Utility	A1
El Paso Electric Company	Vertically Integrated Utility	Baa1
Empire District Electric Company (The)	Vertically Integrated Utility	Baa1
Entergy Arkansas, Inc.	Vertically Integrated Utility	Baa2
Entergy Gulf States Louisiana, LLC	Vertically Integrated Utility	Baa1
Entergy Louisiana, LLC	Vertically Integrated Utility	Baa1
Entergy Mississippi, Inc.	Vertically Integrated Utility	Baa2
Entergy New Orleans, Inc.	Vertically Integrated Utility	Ba2
Entergy Texas, Inc.	Vertically Integrated Utility	Baa3
Florida Power & Light Company	Vertically Integrated Utility	A1
Georgia Power Company	Vertically Integrated Utility	A3
Gulf Power Company	Vertically Integrated Utility	A2
Hawaiian Electric Company, Inc.	Vertically Integrated Utility	Baa1
Idaho Power Company	Vertically Integrated Utility	A3
Indiana Michigan Power Company	Vertically Integrated Utility	Baa1
Interstate Power and Light Company	Vertically Integrated Utility	A3
Kansas City Power & Light Company	Vertically Integrated Utility	Baa1
Kentucky Power Company	Vertically Integrated Utility	Baa2

Madison Gas and Electric Company	Vertically Integrated Utility	A1
MidAmerican Energy Company	Vertically Integrated Utility	A1
Mississippi Power Company	Vertically Integrated Utility	Baa1
Nevada Power Company	Vertically Integrated Utility	Baa1
Northern States Power Company (Minnesota)	Vertically Integrated Utility	A2
Northern States Power Company (Wisconsin)	Vertically Integrated Utility	A2
NorthWestern Corporation	Vertically Integrated Utility	A3
Oklahoma Gas & Electric Company	Vertically Integrated Utility	A1
Pacific Gas & Electric Company	Vertically Integrated Utility	A3
PacifiCorp	Vertically Integrated Utility	A3
Portland General Electric Company	Vertically Integrated Utility	A3
PPL Electric Utilities Corporation	Vertically Integrated Utility	Baa1
Public Service Company of Colorado	Vertically Integrated Utility	A3
Public Service Company of New Hampshire	Vertically Integrated Utility	Baa1
Public Service Company of New Mexico	Vertically Integrated Utility	Baa2
Public Service Company of Oklahoma	Vertically Integrated Utility	A3
Puget Energy, Inc.	Vertically Integrated Utility	Baa3
Puget Sound Energy, Inc.	Vertically Integrated Utility	Baa1
San Diego Gas & Electric Company	Vertically Integrated Utility	A1
Sierra Pacific Power Company	Vertically Integrated Utility	Baa1
South Carolina Electric & Gas Company	Vertically Integrated Utility	Baa2
Southern California Edison Company	Vertically Integrated Utility	A2
Southwestern Electric Power Company	Vertically Integrated Utility	Baa2
Southwestern Public Service Company	Vertically Integrated Utility	Baa1
Tampa Electric Company	Vertically Integrated Utility	A2
Tucson Electric Power Company	Vertically Integrated Utility	Baa1
Union Electric Company	Vertically Integrated Utility	Baa1
Virginia Electric and Power Company	Vertically Integrated Utility	A2
Wisconsin Electric Power Company	Vertically Integrated Utility	A1
Wisconsin Power and Light Company	Vertically Integrated Utility	A1
Wisconsin Public Service Corporation	Vertically Integrated Utility	A1

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MOODY'S
INVESTORS SERVICE

CASE: UE 294
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 211

Frequency of General Rate Case Filings by PGE's Investor Owned Regulated Peer Electric Utilities (As Screened by Staff)

Exhibits in Support of Opening Testimony

June 15, 2015

Frequency of General Rate Case Filings

Frequency of General Rate Cases by Investor Owned Regulated Utilities

Staff Peer Utilities for PGE

Y Indicates a General Rate Case Filing in that Year.

Yreview (**Yrev**) Indicates a Tariff Review Yabbreviated (**Yabr**) Indicates an Abbreviated Rate Case.

Acquired (**Acq**) indicates the Co. was acquired in that year.

#	Abbreviated Electric Utility	Ticker	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1	AEP	AEP																
	AEP Texas		N	N	N	Y	N	N	Y	N	N	N	N	N	N	N	N	N
	AEP App. Pwr (TN)		N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
	AEP Ohio		N	Y	N	N	N	N	N	N	N	N	N	Y	N	N	N	N
	App. Power, VA		N	N	N	N	N	N	N	N	Y	N	N	Yrev	N	N	Yrev	N
	App. Power WVA		N	N	N	N	N	Y	N	N	N	N	Y	N	N	N	Y	N
	Indiana/Michigan IN		N	N	N	N	N	N	N	Y	N	N	N	Y	N	N	N	N
	Indiana/Michigan MI		N	N	N	N	N	N	N	N	N	N	Y	Y	N	N	N	N
	Kentucky Power		N	N	N	N	N	Y	N	N	N	Y	N	N	N	N	Y	N
	PSCo of Okla		N	N	N	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N
	SWEPCO AR		N	N	N	N	N	N	N	N	N	Y	N	N	N	N	N	N
	SWEPCO LA		N	N	N	N	N	N	N	N	Y	N	N	N	N	Y	N	N
	SWEPCO TX		*	*	*	*	*	*	*	*	Acq	Y	N	N	Y	N	N	N
13	DTE (DTE Electric)	DTE	N	N	N	N	Y	N	Y	N	N	Y	N	N	N	N	Y	Y
15	Edison Int'l	EIX	N	N	N	N	Y	N	N	N	N	N	N	N	N	Y	N	N
21	Great Plains	GXP																
	Kansas City P&L (MO)		N	N	N	N	N	N	Y	N	Y	N	Y	N	Y	N	N	N
	KCP&L (Kansas)		N	N	N	N	N	N	Y	Y	Y	Y	N	N	Y	YAbr	N	N
	GMO (MO)		N	N	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N	N
23	IDACORP	IDA																
	IdahoPower (ID)		N	N	N	Y	N	Y	N	Y	Y	N	N	Y	N	N	N	N
	IdahoPower OR)		N	N	N	N	Y	N	N	N	N	Y	N	Y	N	N	N	N
32	Otter Tail	OTTR																
	OtterTail MN		N	N	N	N	N	N	N	Y	N	N	Y	N	N	N	N	N
	OtterTail ND		N	Y	N	N	N	N	N	N	Y	N	N	N	N	N	N	N
	OtterTail SD		N	N	N	N	N	N	N	N	N	N	Y	N	N	N	N	N
34	PG&E	PCG	N	N	Y	Y	N	Y	N	N	N	Y	N	N	Y	N	N	N
37	PNM	PNM																
	PNM (NM)		Y	N	N	Y	N	Y	N	Y	Y	N	Y	N	N	N	Y	N
	PNM (TX)		N	Y	N	N	N	N	N	N	Y	N	Y	N	N	N	N	N
48	Westar	WR	N	Y	N	N	N	Y	N	N	Y	Y Abr	N	N	Y	YAbr	N	Y

CASE: UE 294
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

June 15, 2015

Q. Please state your name, occupation, and business address.

A. My name is George R. Compton. I have been employed by the Public Utility Commission of Oregon since March of 2007. I am a Senior Economist (half-time) within the Energy, Rates, Finance, and Audits Division. My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97308-1088.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/301.

Q. What is the purpose of your testimony?

A. I will be addressing elements of cost allocations, rate spread (i.e., the allocation of the overall revenue increase among the various customer schedules), and pricing/rate design.

Q. Does Staff possess a general philosophy or approach to these subjects?

A. Yes. As a general matter, pricing and customer cost allocations should reflect long-run-incremental cost (LRIC) causation as much as possible. A long-recognized "rates shock" exception to cost causation is to limit class revenue requirement increases to some designated level above the overall average.

Q. Did you prepare exhibits for this docket?

A. Yes. I prepared exhibits connected with each of the topics listed below.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Please give us an overview of your testimony.

A. Over the years Portland General Electric's (PGE's or Company's) practices relating to my areas of responsibility have evolved in a mutually acceptable manner—being influenced by various parties, including Staff. My issues in this testimony have to do with items of departure from past practices. In this docket, the Company introduces an alternative approach to allocating transmission costs. It also proposes rate design and customer impact offset (CIO) modifications in the interest of eventually combining irrigation Schedules 47 and 49 with, respectively, commercial/industrial Schedules 32 and 38. My recommendations are generally to not depart as significantly as PGE has with the status quo and to make modest changes regarding these topics.

Q. Please summarize Staff's position regarding transmission cost allocations?

A. Currently 65 percent of transmission costs are allocated according to the various customer schedules' shares of the sums of the four highest-month (December, January, July, and August) coincident peak demands (i.e., 4 CP), with the remaining 35 percent allocated in proportion to the customer schedules' shares of the energy revenue requirement. The Company now proposes to eliminate energy from the cost allocator and use shares of all twelve coincident peak loads (i.e., 12 CP) as the exclusive transmission costs allocator. Staff recommends staying with the current status quo, except to reduce the energy contribution to 25 percent from the current level of 35 percent.

Q. Would you now please summarize Staff's position regarding the merging of the agricultural Schedules 47 and 49 (Ag) with, respectively, commercial/industrial Schedules 32 and 38 (C/I)?

A. The Company is stating that it wants to eventually consolidate those two pairs of schedules.[1] To that end, the Company in this docket proposes to elevate the C/I's rates and allocations/target revenues and lower those of the Ag schedules beyond what would be called for under standard regulatory and cost-causation practices. Beyond that general theme, two different subsidization strategies are employed. Because Schedule 32 is so much larger than Schedule 47, it was feasible to "pay for" Schedule 47's additional rate reductions by a slight increase in its own rates. Partly because Optional Time-of-Day Schedule 38 is so much smaller in load aggregates than Schedule 49, the Company chose to place the large bulk of the burden of subsidizing Schedule 49's rates upon Schedule 83, whose size-of-load range for customers is comparable to that of Schedules 38 and 49--i.e., minimum loads are in excess of 31 kW. Staff rejects the cross-subsidizations by Schedules 32 and 83, and otherwise recommends setting the subject Ag and C/I rates and allocations as close to cost of service levels as is reasonable.

[1] *See* Exhibit PGE/1400, Cody/22-23.

Topic 1: Transmission Cost Allocation

Q. How are transmission costs currently allocated among the various schedules?

A. The costs have been separated into a demand component, which accounts for 65 percent of the costs, and an energy component that accounts for the remaining 35 percent. The energy portion has been allocated in proportion to the schedules' shares of test period energy revenues; the demand portion has been allocated in proportion to their shares of the sums of the schedules' coincident peak demands for the months December, January, July, and August. The shorthand for the latter is 4CP. A 12CP allocator would employ all twelve monthly coincident peaks.

Q. How has the Company proposed to alter that allocations approach, and what is its justification for doing so?

A. The Company proposes a simple 12CP allocator, with no energy component. The justification is to make it "consistent with how PGE's FERC transmission prices are determined."[2]

Q. On what general grounds does Staff dispute the Company's approach?

A. I see a departure from cost-causation and fairness. Just because PGE and its direct access customers pay rates that are not soundly based upon costs is no reason to compel PGE's own customers to pay rates that are not soundly based.

Q. Please explain.

[2] *See* Exhibit PGE/1400, Cody/5.

A. The cost of a transmission line is a function of its length and of its capacity, or load bearing capability. The capacity is driven by the annual peak load, which will occur in one of the four months listed above. Loads in the off-peak months have no bearing on cost causation. It is for this reason that Staff opposes the PGE proposal to use the twelve coincident peaks to capture load bearing requirements. The length of the transmission line(s) is driven by distances between generation plants and loads and by distances required to interconnect with other utilities' transmission systems. When, for example, transmission costs are reduced by bringing a coal-fired generation plant closer to the primary load or transmission interconnection point, coal transportation costs—which are appropriately allocated according to energy consumption—are increased. That is transmission is a substitute for plant location and rail costs. You can transport the fuel by rail and burn the fuel locally, or you can burn the fuel remotely and use transmission lines to move the electrical power closer to loads. Hence the recognition of an energy component to transmission cost allocations due to the trade-off between the transmission investment and fuel costs. Transmission also serves as a substitute for generation in the sense that interconnection with other utilities and power markets allows for both capacity and fuel/energy cost savings. Given those energy cost-savings implications, it is regarded as fair—based upon benefits received—that customers who use more energy than others should have a somewhat larger allocation of transmission costs.

Q. How is Staff recommending that transmission costs be allocated?

A. We are recommending that schedules' energy shares bear a 25% share of the costs, with the remaining 75 percent allocated using the same 4CP approach as under the status quo.

Q. Why hasn't Staff stuck with the 65 percent capacity share that is currently embodied in rates?

A. Had PGE not proposed a change, Staff would likely have supported remaining with the status quo. However because PGE has proposed a change, Staff has chosen to shift to its 75 percent capacity weighting in recognition of the fact that, traditionally, transmission cost allocation is weighted more heavily on the capacity side. Shrinking the energy weighting also constitutes a compromise with having an allocator that does not weigh energy at all.

Q. Has Staff prepared an exhibit which shows how transmission costs are allocated under the status quo, the Company's proposal, and Staff's counter-proposal?

A. Yes. It is Exhibit Staff/302.

Topic 2: Merging (or Not) Schedules 32 and 47

Q. Owing to their unique load characteristics (i.e., loads preponderantly in the summer) agricultural pumping customers have been served on schedules specifically dedicated to them—i.e., Schedules 47 and 49. What significant change has PGE proposed for these schedules?

A. In the current case the Company has expressed an interest in consolidating those schedules with the commercial/industrial schedules of comparable maximum kW load levels. While the consolidation itself is not being proposed with this docket, prices are being suggested that would move in that direction.[3]

Q. What justification is being offered for this consolidation plan?

A. Basically PGE's justification for consolidating Schedules 38 and 49 is to "achieve cost efficiencies."[4] Similar pricing treatment is proposed for Schedules 32 and 47.[5]

Q. Does Staff favor administrative costs savings?

A. Yes as long as the prices that are a consequence thereof do not violate the cost causation principle in an unacceptable fashion for a significant block of customers. It is Staff's judgment in this case that indeed the Company's rate design and cost allocations would constitute an unacceptable departure from cost causation and other well-accepted utility regulatory principles.

Q. What price movements are being proposed by PGE in this docket in the case of Schedule 47 and the Company-viewed companion Schedule 32?

A. Because the incurred distribution costs are to be recovered over a six-month "summer" period as opposed to an entire year, the Ag schedules distribution-related prices have always been high compared to those of the conventional, year-round C/I schedules. So with rates consolidation the expectation would

[3] *See* Exhibit PGE/1400, Cody/22-23.
[4] *See* Exhibit PGE/1400, Cody/22.
[5] *See* Exhibit PGE/1400, Cody/23.

be to reduce the Ag schedule's distribution price and elevate the companion C/I schedule's distribution price in order to bring the two sets of prices closer together. In the present docket, PGE proposes that small C/I Schedule 32 would have prices somewhat in excess of costs while Schedule 47 would have its corollary prices well below costs. In fact, as shown on page 1 of Exhibit PGE/1402, Cody, the base rates for Schedule 47 would hardly be elevated at all. And the burden of the implicit Schedule 47 subsidy is being borne entirely by the elevation in Schedule 32's prices.[6]

Q. Is it not the norm for the agricultural schedules to have prices well below costs?

A. Yes, but only because these schedules were once well below costs and as opportunity arises rate changes have been slowly transitioning the schedules to a comparable cost-recovery basis. For the past several general rate cases, the Commission has adopted in its orders a rate spread in which agricultural schedules have experienced general rate increases well above the average—as in the 12.5 percent increase the Company is proposing for Schedule 49 (*see* Exhibit PGE/1402, Cody/1). And instead of simply lowering one or more price elements (in this case the distribution charge) well below functionalized costs, the conventional practice is for the price to be kept approximately at costs and the effective subsidy is then taken care of through the customer impact offset (CIO) line item. The CIO application makes the

[6] Page 5 of Cody Exhibit 1403 shows target test period revenues for Schedule 47 as being $1,832 (x1000) *beneath* the functional cost allocation (i.e., $5,534 minus $3,702), while Page 4 of Cody Exhibit 1403 shows target test period revenues for Schedule 32 as being $1,821 (x1000) *above* the functional cost allocation (i.e., $181,839 minus $180,018).

subsidy transparent, and instead of the subsidy being borne by a particular customer schedule, it is normally spread among a number of schedules—typically those for which the proposed percentage revenue increases are beneath the overall system average.

Q. How do you propose to price agricultural Schedule 47?

A. In the conventional way, i.e., by setting the distribution charge near cost and using the CIO credit to bring the overall increase down to the rate-shock-mitigating 12.5 percent ceiling.

Q. Have you prepared an exhibit which shows your and the Company's rates and revenue target proposals for Schedule 47?

A. Yes, it is Page 1 of Exhibit Staff/303. The point of departure for this exhibit is Mr. Cody's Exhibit PGE/1403. It assumes that the Company will receive the revenue increase that it has requested and that the functionalized cost allocations will remain the same. While those assumptions will likely not hold up when this docket is ultimately resolved, in order to make clear the policy distinctions between Staff and PGE, it is expedient for this exhibit to share a common foundation, i.e., the Company's applied-for revenue requirement and functional cost-of-service allocations.

Q. Would you please describe key elements in your exhibit and note its conclusions?

A. Yes. The top portion of Exhibit Staff/303 shows the Company's functional long-run incremental cost allocations. For most schedules these functional elements set the target prices for the respective prices that appear below. In this answer I will point out how PGE departs from that practice in setting the prices contained in Schedule 47. Similar points will be made later in this testimony with regard to Schedules 32, 38, and 49. Contrasting sets of prices are highlighted: most of the Company's pricing proposals (i.e., the non-highlighted ones) are also accepted. The difference in the two revenue targets is also shown. PGE would have Schedule 47's revenue target be 33 percent below its own functionalized cost-of-service estimate of costs. That reduction is achieved by setting the distribution charge at about half its functionalized cost. Staff keeps the energy and distribution charges near their functionalized costs and holds the revenue target increase at 12.5 percent by use of a substantial CIO credit. The 12.5 percent is the PGE-recommended increase for agricultural Schedule 49 shown on page 1 of Mr. Cody's Exhibit PGE/1402. Staff accepts that recommendation, and would apply it to both agricultural schedules. The resulting revenue target for Schedule 47 comes out to be 25 percent below the cost-of-service estimate.[7]

Q. Assuming that in the aggregate the schedules' target revenues are to sum to the overall target revenue requirement, when one schedule's target is beneath its costs then other schedules' targets must be in excess of costs. As described above, the function of the CIO is to make explicit the burdens that the various customer schedules must bear in order that other schedules' target revenues can be beneath their

[7] PGE: (5,534 – 3,702) / 5,534 = 33%. Staff: (5,534 – 4,154) / 5,534 = 25%.

functionalized costs of service. Was that the case under the Company's proposal?

A. No, it was not. As I testified earlier, instead of spreading the burden over several different customer schedules via the CIO mechanism, the Company would place the entire burden on small C/I Schedule 32. (Again, the justification was to elevate Schedule 32's rates to bring them closer in conformance with Schedule 47's rates—with eventual consolidation of Schedules 32 and 47 in mind.) Staff regards forcing Schedule 32 to bear the entire burden of lowering Schedule 47's rates far below costs as quite unfair. We would also look upon consolidation itself with disfavor if it "artificially" elevates to levels above their own costs the rates that the Schedule 32 customers would have to pay. Staff is uncomfortable with penalizing Schedule 32 customers for having to be paired up with agricultural customers for the sake of incidental administrative cost savings.

Q. Rejecting the intent to consolidate Schedule 32 with Schedule 47 in the manner implicit in this docket, how would you alter PGE's Schedule 32 revenue target and rate design?

A. In common with the Company, distribution charges must be something above functionalized costs in order to compensate for basic charges being beneath their functionalized costs. My only departure from the Company would be to elevate Schedule 32's distribution charges only to the degree that the target will equal the schedule's total functionalized cost of service.

Q. Have you prepared an exhibit which displays what you have just described for Schedule 32?

A. Yes, it is Page 2 of Exhibit Staff/303.

Q. So is your only concern regarding consolidating Schedules 32 and 47 the fact that Schedule 32 would be the sole "subsidizer" of Schedule 47?

A. No. Schedules 32 and 47 have significant cost of service differences that justify keeping them as separate schedules.

Topic 3: Merging (or Not) Schedules 38 and 49

Q. You previously testified that PGE has also expressed a desire to eventually merge Optional Time-of-Day Schedules 38 with Ag Schedule 49. Does the Company approach that consolidation through elevating and suppressing rates in the same manner as they approached an eventual Schedules 32 and 47 consolidation, i.e., by bringing one of Schedule 49's rate component's price to a level well below costs and having Schedule 38 bear the burden of the Schedule 49 subsidy be experiencing rates that are well above costs?

A. No, the Company approaches things quite differently here. The reason is that Schedule 32 is very much larger than Schedule 47, and can therefore absorb an extra cost burden without an inordinate increase in its own rates…while on the other hand, Schedule 38 is substantially smaller than Schedule 49, making it not feasible for the Schedule 38 customers to subsidize Schedule

49 in a material way by elevating its own rates. In the interest of an eventual schedule consolidation, PGE does in fact move Schedule 38's rates well above the cost-of-service justified level, but the outcome is not a significant level of subsidy for Schedule 49.

Q. So what is PGE's Schedule 49 subsidization proposal in this case?

A. It is to subsidize Schedule 49 in the usual CIO manner, but rather than having the CIO burden be shared by a number of other customer schedules (i.e., also in the usual manner), the CIO burden would be placed almost entirely upon C/I Schedule 83.

Q. How does PGE justify placing that burden upon Schedule 83?

A. If there were no Schedule 49 at all, then given its minimum load level (i.e., 30 kW), most of those Schedule 49 customers would be part of Schedule 83, thereby bringing up that schedule's average costs.

Q. Is PGE proposing to merge Schedule 49 with C/I Schedule 83?

A. No.

Q. Is Staff persuaded by PGE's logic for having Schedule 83 subsidize Ag Schedule 49?

A. No. With Schedules 32 and 47 the Company in essence is saying, "We want to eventually consolidate those schedules, so we will lower Schedule 47's rates and elevate Schedule 32's to move us a long way towards what the consolidated rates would look like, and we'll do it in a way that does not burden other customer schedules." With Schedules 38 and 49 the Company in essence is saying, "We want to eventually consolidate those schedules, and we will move their rates together somewhat in this docket. But PGE cannot elevate Schedule 38's rates enough to allow us to materially lower Schedule 49's rates, so we'll elevate Schedule 83's rates even though there is no intention to combine Schedule 49 with Schedule 83…but *if* they were combined then Schedule 83's average rates would indeed go up." In my mind, expressing the Company's positions in those simple and straightforward ways, makes rejecting the Company's approach to dealing with Schedule 83 also simple and straightforward. Alternatively, it can be stated that when two sets of customers have materially different load patterns in an overall sense, then one set of customers should not be penalized simply because of a similarity in one aspect of its load characteristics (in this case their minimum or maximum loads).

Q. You indicated that the Company aspires to consolidating Schedules 38 and 49, does PGE shrink some of the latter schedule's rates in comparison with the corresponding functionalized costs in a manner comparable to what they did with Schedule 47?

A. Yes, but not to the same degree because with Schedule 49 there is a aforementioned major CIO credit to contribute to the subsidy.

Q. Have you prepared an exhibit which displays how you believe Schedule 49 should be structured?

A. Yes, it is page 1 of Exhibit Staff/304.

Q. Please summarize the conclusions from that exhibit.

A. Compared to the PGE proposal, the energy and distribution charges are set to levels closer to their respective functionalized costs. In order to avoid revenues that exceed the target, it was necessary to elevate the CIO credit to offset the increased revenues from the energy and distribution charges.

Q. Does the elevation of the CIO credit translate to a net subsidy burden on the part of other customer schedules?

A. No it does not…at least it should not. Offsetting the increased CIO credit should be a reduction in the other rates and associated cost allocations that are experienced by the other customer schedules. For example, elevating the energy charge as indicated means that Schedule 49 would now be contributing more toward covering energy costs; therefore the energy cost burden borne by all other, or selectively other, schedules can be smaller than it otherwise would be. As currently constructed, the Company's cost allocation/rate spread/rate design model lacks the dexterity to adjust the rates of more than a single tied-in schedule in order to do what I have just described. However, given the need, the model can be appropriately expanded.

Q. What is PGE proposing to do in this docket with Schedule 38?

A. In the interest of moving Schedule 38's rates closer to those of Schedule 49, PGE proposes to elevate Schedule 38's energy and distribution charges above their functionalized cost of service levels. (A small increase in the distribution charge was also required to offset low basic charges.) But in elevating those charges, the target revenue requirement of Schedule 38 would be raised to a grossly unacceptable level. To avoid this latter condition, the Company proposes the significant CIO credit offset that was mostly directed to Schedule 83.

Q. How would you set the prices for Schedule 38?

A. Compared to the Company proposal, I would lower the distribution and energy prices to be as close as reasonable to their functionalized cost of service levels with the intent of meeting target revenues that equal the total functionalized cost of service for this customer schedule.

Q. Have you prepared an exhibit which displays what you have just described?

A. Yes, it is Page 2 of Exhibit Staff/304.

Q. What is the overall percentage increase in base rates that PGE is requesting?

A. It is 2.1 percent.[8]

Q. I see from Page 2 of your Exhibit Staff/304 that you would have Schedule 38's revenue target go up by 5.5 percent relative to what would be produced by rates now in effect, while the Company is proposing an 11.3 percent increase. Do you have any comment?

A. Yes. Another key argument against elevating Schedule 38's rates for the "mere" purpose of bringing them closer to Ag Schedule 49 rates is that the Company's cost allocations already suggest an increase that is more than

[8] *See* Exhibit PGE/1402, Cody/1.

twice the overall average. It would be grossly unfair to more than double down on that increase—taking it to more than five times the overall average percentage increase.

Q. Do you support the goal of consolidating Schedule 38 and Schedule 49?

A. No. These schedules have sufficient cost differences that it does not make sense to combine the schedules, or to move toward consolidation at this time.

Topic 4: Miscellaneous Items

Q. Staff witness Suparna Bhattacharya performed analyses on the subject of generation long-run incremental costs. Are you familiar with her work?

A. Yes I am.

Q. What impact will her results have on the various customer schedules?

A. Final results await additional input from PGE. But the general thrust is to elevate generation cost allocations to high load factor industrial customers, and reduce them for the lower load factor residential customers. Basing conclusions on prior Company inputs, Schedules 7, 83, and 85 would be slightly net beneficiaries from a combination of Staff's transmission and generation cost allocations, and Schedules 89 and 90 would receive slightly larger net cost allocations. When I say "slightly" I mean, in the case of a "harmed" customer, something in the neighborhood of $120 thousand out of a $90 million revenue requirement. That means the impacts of Staff's recommendations in this regard are not significant.

Q. In reviewing Tables 1 through 5 of Exhibit PGE1402, I see that all of the direct access customers are to achieve large-percentage decreases—sometimes close to 40 percent. Did that initially raise some concerns?

A. Yes in the sense of provoking something of an investigation into the underlying causes. However, after my review I support PGE's recommendations for this issue.

Q. What did you find that led you to this conclusion?

A. Bear in mind that direct access customers pay facilities and basic charges that are identical to those paid by their parallel full-service retail customers.[9] It turns out that in the docket that established current rates, UE 283, the facilities charge picked up an "Under-recovery of other charges" that was a large dollar figure and the basic, or customer, charge picked up a large magnitude of "Other Consumer" costs. I accept PGE's representation that recent cost allocation accounting and modelling refinements have placed a lot of the subject dollars into categories which, unlike the facilities and basic charge, do not serve as a repository for costs that heretofore were not readily categorized. The presumption is that the facilities and basic charges proposed in the current docket are more expressly cost based than are their predecessors, and are therefore worthy of adoption.

Q. Have you prepared an exhibit which displays the differences between UE 283 and UE 294 regarding "Other Consumer" costs and the "Under-recovery of other charges" relating to facilities charges?

[9] For example, Schedule 485-P customers pay the same basic charge as is paid by Schedule 85-P customers.

A. Yes, Exhibit Staff/305. Contrast the highlighted figures on Page 1 with those on Page 2 of this exhibit to see a dramatic reduction in the facilities charges under-recovery between Dockets 283 and 294; and contrast the highlighted figures on Page 3 with those on Page 4 to see the dramatic reduction in "Other Consumer" costs.

Q. PGE proposes to increase its residential monthly customer charge from $10 to $11. Does Staff approve?

A. In this case where, disregarding Carty, overall basic rates are likely to move hardly at all, Staff is uncomfortable with the proposed ten percent increase in the customer charge. As a general rule we accept modest customer charge increases over time so as to match incremental customer costs, which are indeed somewhat above the $11 dollar figure. Placing that general rule in the context of a modest general rate increase, perhaps a 50 cent per month increase would be appropriate—*provided such would not lead to decreases in other non-fuel-related charges.*

Q. Can your recommendations regarding Schedules 32, 38, 47, 49, and 83, be summarized as a) Schedule 32 should not be required to subsidize Schedule 47, b) the target revenues for Schedules 32 and 38 should be their own functionalized cost allocations, c) target revenue increases for both Schedule 47 and 49 should be 12.5 percent, with the subsidies coming through the conventional CIO mechanism, and d) Schedule 83 should not have to bear the brunt of the cross-schedule subsidies, primarily for Schedule 49?

A. Yes.

Q. Does Staff have a recommendation regarding what rates should go into the CIO mechanism?

A. Yes. In the past Staff has recommended that contributions into the CIO balance should come from customer schedules which otherwise would enjoy increases beneath the overall system average. There is ambiguity in that regard in the current docket. Referring to page 1 of Exhibit PGE/1402, one sees that the proposed residential increase exceeds the average and the industrial schedule increases are beneath the average[10]—arguing for the industrials to bear the primary CIO burden. On the other hand, referring to page 5 of that same exhibit shows the residential schedule receiving an increase that is beneath the overall average.[11] Absent a clear picture regarding whether the residential or the industrial customers should bear the CIO burden, it is Staff's recommendation to spread the burden across *all* the major schedules, which would add Schedule 32 to Residential Schedule 7 and the large industrial Schedules 83, 85, 89, and 90. Referring to page 1 of both my Exhibits Staff/303 and Staff/304, it is seen that the combined CIO subsidy for the two agricultural schedules is approximately $6 million. Dividing that amount by the approximately 19.2 million MHW large schedule consumption yields Staff's recommended CIO mill rate of 0.3 mills, or 0.03

[10] Schedule 83 appears as the exception, with an increase of 3.1%. But that figure is a consequence of the Company's placing the CIO burden almost entirely upon that schedule—contrary to Staff's recommendation. Eliminating that unjustified (in Staff's estimation) burden brings Schedule 83's increase down to the one percent range.

[11] The difference between page 1 and page 5 is that the latter adds Carty to the revenue requirement. The page 5-related rates are not to go into effect until Carty is actually in service, which is expected to occur during the second quarter of 2016.

cents, per kWh. That compares with the PGE proposed Schedule 83 mill rate of 1.73 mills per kWh.[12]

Q. Does this conclude your direct testimony?

A. Yes.

[12] *See* Exhibit PGE/1403, Cody/11.

CASE: UE 294
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualification Statement

June 15, 2015

WITNESS QUALIFICATION STATEMENT

NAME: George R. Compton

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Energy Rates, Finance & Audit

ADDRESS: 3930 Fairview Industrial Dr SE
Salem, OR 97308-1088

EDUCATION: Doctor of Philosophy, Economics (1976)
University of California, Los Angeles (UCLA) – Westwood, CA

Master of Science, Statistics (1968)
Brigham Young University (BYU) – Provo, UT

Bachelor of Science, Mathematics and Psychology (1963)
Brigham Young University – Provo, UT

EXPERIENCE: I have been employed in utility regulation since receiving my Ph.D. in 1976. My primary employer was the Division of Public Utilities, within Utah's Department of Commerce (formerly Business Regulation). I also consulted for a couple of years, early in that period. I testified frequently during my career on rate design, cost-of-service, cost-of-equity, and various policy matters affecting electric, gas, and telephone utilities. While in Utah, I also taught Economics part-time for about ten years at BYU.

Prior to my utility regulatory career, I worked in aerospace for eleven years at McDonnell Douglas (now Boeing) in Southern California.

I joined the OPUC staff soon after "retiring" to Oregon at the end of 2006. Principal cases of my involvement here have included the IRP/CO_2 Risk Guideline (UM 1302), an Avista General Rate Case (UG 181 and 284), PGE General Rate Cases (UE 197, UE 215, UE 262, and UE 283), PacifiCorp General Rate Cases (UE210, UE 246, and UE 263), the NW Natural General Rate Case (UG 221), and the Idaho Power General Rate Case (UE 233).

CASE: UE 294
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

June 15, 2015

PORTLAND GENERAL ELECTRIC

ALLOCATION OF TRANSMISSION REVENUE REQUIREMENT

2016

PGE Proposal

Schedules	Transmission Allocation Percent	Class Revenue Requirement (x1000)	Rank
Schedule 7	48.53%	$16,232	
Schedule 15	0.05%	$16	L
Schedule 32	8.70%	$2,910	L
Schedule 38	0.18%	$62	H
Schedule 47	0.12%	$40	H
Schedule 49	0.36%	$122	H
Schedule 83	15.21%	$5,087	H
Schedule 85	11.80%	$3,945	H
Schedule 85 1-4 MW	4.45%	$1,487	
Schedule 89 GT 4 MW	4.05%	$1,353	
Schedule 90-P	6.32%	$2,112	L
Schedules 91/95	0.22%	$73	L
Schedule 92	0.01%	$4	L
Target	100.00%	$33,444	
12 CP Capacity Allocation	100%		
Energy Allocation	0%		

UE 283

Schedules	Transmission Allocation Percent	Class Revenue Requirement (x1000)	Rank
Schedule 7	48.07%	$16,076	L
Schedule 15	0.07%	$24	H
Schedule 32	8.85%	$2,961	H
Schedule 38	0.18%	$62	H
Schedule 47	0.15%	$51	
Schedule 49	0.47%	$159	
Schedule 83	14.96%	$5,004	
Schedule 85	11.63%	$3,889	
Schedule 85 1-4 MW	4.45%	$1,489	H
Schedule 89 GT 4 MW	4.17%	$1,395	H
Schedule 90-P	6.63%	$2,219	H
Schedules 91/95	0.33%	$110	H
Schedule 92	0.01%	$5	H
Target	100.00%	$33,444	
4 CP Capacity Allocation	65%		
Energy Allocation	35%		

OPUC Staff Proposal

Schedules	Transmission Allocation Percent	Class Revenue Requirement (x1000)	Rank
Schedule 7	48.83%	$16,330	H
Schedule 15	0.07%	$23	
Schedule 32	8.83%	$2,953	
Schedule 38	0.18%	$60	L
Schedule 47	0.16%	$53	H
Schedule 49	0.49%	$165	H
Schedule 83	14.85%	$4,966	L
Schedule 85	11.46%	$3,833	L
Schedule 85 1-4 MW	4.36%	$1,457	L
Schedule 89 GT 4 MW	4.04%	$1,350	L
Schedule 90-P	6.40%	$2,141	
Schedules 91/95	0.32%	$106	
Schedule 92	0.01%	$4	L
Target	100.00%	$33,444	
4 CP Capacity Allocation	75%		
Energy Allocation	25%		

"H" denotes the highest value of the three; "L" denotes the lowest.

Source of Transmission Allocation Percentages: The "Peaks" tab of PGE UE 294 Exhibit 1400 workpapers.

Exhibit Staff/302

CASE: UE 294
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 303

Exhibits in Support
Of Opening Testimony

June 15, 2015

PORTLAND GENERAL ELECTRIC
SCHEDULE 47 FUNCTIONAL COST ALLOCATIONS AND RATE DESIGN
2016

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 47						
Irrig. & Drain. Pump. - < 30 kW						
Allocations						
Functional Costs						
Basic Charge						
Single-Phase	56	231	Customers	$40.74	per cust. per summ. mo.	56
Three-Phase	841	2,921	Customers	$47.97	per cust. per summ. mo.	841
Trans. & Rel. Serv. Charge	47	20,845	MWh	2.26	mills/kWh	47
Distribution Charges	2,920	20,845	MWh	140.07	mills/kWh	2,920
Franchise Fees & Other	142	20,845	MWh	6.82	mills/kWh	142
Energy Charge	1,528	20,845	MWh	73.29	mills/kWh	1,528
Subtotal	**5,534**	**= total functionalized cost allocation**				5,534

PGE Proposed Pricing

	Amount	Unit	Rate	Unit	Annual Revenue ($000)
Functional Costs					
Basic Charge					
Single-Phase	231	Customers	44	per cust. per summ. mo.	61
Three-Phase	2,921	Customers	44	per cust. per summ. mo.	771
Trans. & Rel. Serv. Charge	20,845	MWh	2.1	mills/kWh	44
Distribution Charge Calc					
First 50 kWh per kW	7,404	MWh	76.77	mills/kWh	568
Over 50 kWh per kW	13,441	MWh	66.77	mills/kWh	897
System Usage Charge Calc					-
Franchise Fees & Other	20,845	MWh	2.99	mills/kWh	62
Cust Impact Offset	20,845	MWh	0	mills/kWh	-
System Usage Charge	20,845	MWh	2.99	mills/kWh	62
Energy Charge	20,845	MWh	62.27	mills/kWh	1,298
Reactive Demand Charge	76	kVar	0.5	kVar	0.0
Subtotal with Consumer Impact Offset				**Revenue Target**	3,702

Staff Proposed Pricing

	Amount	Unit	Rate	Unit	Annual Revenue ($000)
Functional Costs					
Basic Charge					
Single-Phase	231	Customers	44	per cust. per summ. mo.	61
Three-Phase	2,921	Customers	44	per cust. per summ. mo.	771
Trans. & Rel. Serv. Charge	20,845	MWh	2.1	mills/kWh	44
Distribution Charge Calc					
First 50 kWh per kW	7,404	MWh	142	mills/kWh	1,051
Over 50 kWh per kW	13,441	MWh	139	mills/kWh	1,868
System Usage Charge Calc					-
Franchise Fees & Other	20,845	MWh	2.99	mills/kWh	62
Cust Impact Offset	20,845	MWh	(58.82)	mills/kWh	(1,226)
System Usage Charge	20,845	MWh	(55.83)	mills/kWh	(1,164)
Energy Charge	20,845	MWh	73	mills/kWh	1,522
Reactive Demand Charge	76	kVar	0.5	kVar	0.0
Subtotal with Consumer Impact Offset				**Revenue Target**	**4,154**

Current Revenues (from Page 1 of Cody Exhibit 1402): **$3,692,050**
Revenue Target = 1.125 times Current Revenues = **$4,153,556**

Observation: Staff elevates energy and distribution charges to be close to functional cost and employs the CIO to bring the revenue target down to 12.5% above current revenues.

Source of Functional Cost Allocations and PGE-Proposed Pricing: PGE UE 294 Exhibit 1403, Cody, Page 5

PORTLAND GENERAL ELECTRIC
SCHEDULE 32 FUNCTIONAL COST ALLOCATIONS AND RATE DESIGN
2016

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 32						
General Service <30 kW						
Allocations						
Functional Costs						
Basic Charge						
Single-Phase	$17,335	54,838	Customers	$26.34	per cust. per mo.	17,333
Three-Phase	$19,297	35,546	Customers	$45.24	per cust. per mo.	19,297
Trans. & Rel. Serv. Charge	$3,352	1,599,950	MWh	2.10	mills/kWh	3,360
Distribution Charge	$35,913	1,599,950	MWh	22.45	mills/kWh	35,919
Franchise Fees & Other	$4,705	1,599,950	MWh	2.94	mills/kWh	4,704
Energy Charge	$99,407	1,599,950	MWh	62.13	mills/kWh	99,405
Subtotal	**$180,009**	**= Staff's Target Revenues**				180,018

PGE Proposed Pricing					
Functional Costs					
Basic Charge					
Single-Phase	54,838	Customers	$16.00	per cust. per mo.	10,529
Three-Phase	35,546	Customers	$22.00	per cust. per mo.	9,384
Trans. & Rel. Serv. Charge	1,599,950	MWh	2.10	mills/kWh	3,360
Distribution Charge					
First 5 MWh	1,408,301	MWh	37.50	mills/kWh	52,811
Over 5 MWh	191,649	MWh	7.00	mills/kWh	1,342
System Usage Charge Calc					
Franchise Fees & Other	1,599,950	MWh	2.99	mills/kWh	4,784
Cust Impact Offset	1,599,950	MWh	0.00	mills/kWh	-
System Usage Charge	1,599,950	MWh	2.99	mills/kWh	4,784
Energy Charge	1,599,950	MWh	62.27	mills/kWh	99,629
Subtotal				**Target Revenues**	181,839

Staff Proposed Pricing					
Functional Costs					
Basic Charge					
Single-Phase	54,838	Customers	$16.00	per cust. per mo.	10,529
Three-Phase	35,546	Customers	$22.00	per cust. per mo.	9,384
Trans. & Rel. Serv. Charge	1,599,950	MWh	2.10	mills/kWh	3,360
Distribution Charge					
First 5 MWh	1,408,301	MWh	36.25	mills/kWh	51,051
Over 5 MWh	191,649	MWh	6.64	mills/kWh	1,273
System Usage Charge Calc					
Franchise Fees & Other	1,599,950	MWh	2.99	mills/kWh	4,784
Cust Impact Offset	1,599,950	MWh	0.00	mills/kWh	-
System Usage Charge	1,599,950	MWh	2.99	mills/kWh	4,784
Energy Charge	1,599,950	MWh	62.27	mills/kWh	99,629
Subtotal				**Target Revenues**	180,009

Observations:

1. Distribution charge is elevated under both proposals to compensate for basic charges being beneath allocations.
2. Staff reduces distribution charge slightly compared to PGEin order to achieve the slightly lower revenues target.

Source of Functional Cost Allocations and PGE-Proposed Pricing: PGE UE 294 Exhibit 1403, Cody, Page 4

CASE: UE 294
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 304

Exhibits in Support
Of Opening Testimony

June 15, 2015

PORTLAND GENERAL ELECTRIC
SCHEDULE 49 FUNCTIONAL COST ALLOCATIONS AND RATE DESIGN
2016

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 49						
Irrig. & Drain. Pump. - < 30 kW						
Allocations						
Functional Costs						
Basic Charge						
Single-Phase	$2	3	Customers	$94.39	per cust. per summ. mo.	$2
Three-Phase	$779	1,346	Customers	$96.51	per cust. per summ. mo.	$779
Trans. & Rel. Serv. Charge	$142	62,677	MWh	2.27	mills/kWh	$142
Distribution Charges	$8,451	62,677	MWh	134.83	mills/kWh	$8,451
Franchise Fees & Other	$369	62,677	MWh	5.89	mills/kWh	$369
Energy Charge	$4,562	62,677	MWh	72.79	mills/kWh	$4,562
Subtotal	**$14,306**					$14,306

PGE Proposed Pricing

Functional Costs					
Basic Charge					
Single-Phase	3	Customers	$50.00	per cust. per summ. mo.	$1
Three-Phase	1,346	Customers	$50.00	per cust. per summ. mo.	$404
Trans. & Rel. Serv. Charge	62,677	MWh	2.10	mills/kWh	$132
Distribution Charge Calc					
First 50 kWh per kW	20,023	MWh	121.46	mills/kWh	$2,432
Over 50 kWh per kW	42,655	MWh	111.46	mills/kWh	$4,754
System Usage Charge Calc					
Franchise Fees & Other	62,677	MWh	5.05	mills/kWh	$317
Cust Impact Offset	62,677	MWh	(55.19)	mills/kWh	($3,459)
System Usage Charge	62,677	MWh	(50.14)	mills/kWh	($3,143)
Energy Charge	62,677	MWh	67.31	mills/kWh	$4,219
Reactive Demand Charge	11,083	kVar	0.50	kVar	$6
Subtotal with Consumer Impact Offset				**Revenue Target**	$8,804

Staff Proposed Pricing

Functional Costs					
Basic Charge					
Single-Phase	3	Customers	$50.00	per cust. per summ. mo.	1
Three-Phase	1,346	Customers	$50.00	per cust. per summ. mo.	404
Trans. & Rel. Serv. Charge	62,677	MWh	2.10	mills/kWh	132
Distribution Charge Calc					
First 50 kWh per kW	20,023	MWh	137.00	mills/kWh	2,743
Over 50 kWh per kW	42,655	MWh	127.00	mills/kWh	5,417
System Usage Charge Calc					-
Franchise Fees & Other	62,677	MWh	5.05	mills/kWh	317
Cust Impact Offset	62,677	MWh	(76.27)	mills/kWh	(4,781)
System Usage Charge	62,677	MWh	(71.22)	mills/kWh	(4,464)
Energy Charge	62,677	MWh	73	mills/kWh	4,575
Reactive Demand Charge	11,083	kVar	0.50	kVar	0.0
Subtotal with Consumer Impact Offset				**Revenue Target**	**8,808**

Current Revenues (from Page 1 of Cody Exhibit 1402): **$7,829,234**
Revenue Target = 1.125 times Current Revenues = **$8,807,888**

Observation: Staff elevates energy and distribution charges to be close to functional cost and employs the CIO to bring the revenue target down to 12.5% above current revenues.

Source of Functional Cost Allocations and PGE-Proposed Pricing: PGE UE 294 Exhibit 1403, Cody, Page 5

PORTLAND GENERAL ELECTRIC
SCHEDULE 38 FUNCTIONAL COST ALLOCATION AND RATE DESIGN
2016

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 38						
Time-of-Day G.S. >30 kW						
Allocations						
Functional Costs						
Basic						
Single-Phase	76	66	Customers	$95.74	per cust. per mo.	76
Three-Phase	827	482	Customers	$143.04	per cust. per mo.	827
Trans. & Rel. Serv. Charge	72	39,036	MWh	1.84	per cust. per mo.	72
Distribution Charges	2,134	39,036	MWh	54.68	per cust. per mo.	2,134
Franchise Fees & Other	144	39,036	MWh	3.70	mills/kWh	144
Energy Charge	2,284	39,036	MWh	58.52	mills/kWh	2,284
Subtotal	5,538	**= Staff's Target Revenues**				5,538
Current Revenues ($1000; from Page 1 of Cody Exhibit 1402):				**5,250.6**		

PGE Proposed Pricing

Functional Costs					
Basic					
Single-Phase	66	Customers	$25.00	per cust. per mo.	20
Three-Phase	482	Customers	$25.00	per cust. per mo.	145
Trans. & Rel. Serv. Charge	39,036	MWh	2.10	mills/kWh	82
Distribution Charges	39,036	MWh	114.66	mills/kWh	4,476
System Usage Charge					
Franchise Fees & Other	39,036	MWh	5.05	mills/kWh	197
Cust Impact Offset	39,036	MWh	(44.45)	mills/kWh	(1,735)
System Usage Charge	39,036	MWh	(39.40)	mills/kWh	(1,538)
Energy Charge Calc					
On-Peak (special)	21,383	MWh	71.83	mills/kWh	1,536
Off-Peak	17,653	MWh	61.83	mills/kWh	1,091
Reactive Demand Charge	66,989	kVar	0.50	kVar	33
Subtotal			**Target Revenues =**		5,845
Implied Proposed Percentage Increase:			**11.3%**		

Staff Proposed Pricing

Functional Costs					
Basic					
Single-Phase	66	Customers	$25.00	per cust. per mo.	20
Three-Phase	482	Customers	$25.00	per cust. per mo.	145
Trans. & Rel. Serv. Charge	39,036	MWh	2.10	mills/kWh	82
Distribution Charges	39,036	MWh	64.18	mills/kWh	2,505
System Usage Charge					
Franchise Fees & Other	39,036	MWh	5.05	mills/kWh	197
Cust Impact Offset	39,036	MWh	0.00	mills/kWh	-
System Usage Charge	39,036	MWh	5.05	mills/kWh	197
Energy Charge Calc					
On-Peak (special)	21,383	MWh	70.00	mills/kWh	1,497
Off-Peak	17,653	MWh	60.00	mills/kWh	1,059
Reactive Demand Charge	66,989	kVar	0.50	kVar	33
Subtotal			**Target Revenues =**		5,538
Implied Proposed Percentage Increase:			**5.5%**		

Observation: Compared to PGE's proposal, Staff brings the energy and distribution charges down close to their functional allocations, and at a level consistent with achieving the target revenues without relying upon the CIO.

Source of Functional Cost Allocations and PGE-Proposed Pricing: PGE UE 294 Exhibit 1403, Cody, Page 4

CASE: UE 294
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 305

Exhibits in Support
Of Opening Testimony

June 15, 2015

PORTLAND GENERAL ELECTRIC

Commercial and Industrial Pricing: **UE 283**

	Allocated Inputs ($000)	Billing Determinants Amount	Unit	Rate	Rate Unit	Note	Annual Revenue ($000)
Schedule 89 Facility Charges	$4,189						
Under-recovery of other charges	$3,255						
Total Facilities Revenues to Recover	$7,444	4,501,188	kW faccap	$1.65	per kW faccap		$7,427
Secondary							
First 4,000		48,000	kW faccap	$1.97	per kW faccap		$95
Over 4,000		53,112	kW faccap	$1.50	per kW faccap		$80
Primary							
First 4,000		1,296,000	kW faccap	$1.94	per kW faccap		$2,514
Over 4,000		1,309,032	kW faccap	$1.47	per kW faccap		$1,924
Subtransmission							
First 4,000		384,000	kW faccap	$1.94	per kW faccap		$745
Over 4,000		1,411,044	kW faccap	$1.47	per kW faccap		$2,074
							$7,432

Source: The "Price-volt" tab of Ratespread15GRC folder within UE 283 PGE Exhibit 1400 workpapers.

PORTLAND GENERAL ELECTRIC

Commercial and Industrial Pricing: **UE 294**

	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Rate Note	Annual Revenue ($000)
Schedule 89 Facility Charges	$4,050						
Under-recovery of other charges	$327						
Total Facilities Revenues to Recover	$4,378	4,557,428	kW faccap	$0.96	per kW faccap		$4,375
Secondary							
First 4,000		48,000	kW faccap	$0.99	per kW faccap		$47
Over 4,000		49,536	kW faccap	$0.99	per kW faccap		$49
Primary							
First 4,000		1,296,000	kW faccap	$0.96	per kW faccap		$1,244
Over 4,000		1,411,040	kW faccap	$0.96	per kW faccap		$1,354
Subtransmission							
First 4,000		384,000	kW faccap	$0.96	per kW faccap		$368
Over 4,000		1,368,852	kW faccap	$0.96	per kW faccap		$1,313
							$4,376

Source: The "Price-volt" tab of UE 294 PGE Exhibit 1400 workpapers.

PORTLAND GENERAL ELECTRIC – **UE 283**

RATE DESIGN INPUTS (CONTINUED)

SUMMARY - ALLOCATION OF 2015 COSTS TO RATE SCHEDULES ($000)

	Dist. Customer-Relate		Uncollectibles		Metering		Billing		Other Consumer		Subtotal				Total
Grouping	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Fixed Costs	Subtotal	Cost Allocations
Schedule 7	$92,593	$22	$7,514	$1	$1,743	$0	$48,614	$6	$39,358	$5	$189,821	$33		$189,855	$879,952
Schedule 15	$244		$24		$0		$138		$76		$482	$0	$1,997	$2,479	$3,751
Schedule 32	$8,866	$13,961	$259	$168	$201	$130	$3,358	$2,181	$3,083	$2,002	$15,767	$18,443		$34,210	$168,185
Schedule 38	$17	$453	$0	$1	$2	$24	$4	$37	$4	$42	$28	$557		$584	$5,715
Schedule 47	$18	$379	$1	$9	$1	$9	$11	$147	$8	$106	$38	$649		$688	$5,046
Schedule 49	$1	$381	$0	$21	$0	$8	$0	$91	$0	$51	$1	$552		$553	$15,835
Schedule 83															
Secondary	$339	$14,609	$11	$173	$17	$272	$100	$1,570	$130	$2,051	$598	$18,674		$19,272	$235,923
Schedule 85															
Secondary		$3,000		$36		$89		$858		$2,650	$0	$6,631		$6,631	
Primary		$442		$4		$10		$101		$311	$0	$868		$868	$171,140
Schedule 85 1-4 MW															
Secondary		$441		$11		$3		$46		$681	$0	$1,182		$1,182	
Primary		$235		$11		$4		$47		$696	$0	$993		$993	$67,693
Schedule 89 GT 4 MW															
Secondary		$19		$13		$0		$1		$98	$0	$131		$131	
Primary		$146		$349		$0		$14		$2,644	$0	$3,154		$3,154	
Subtransmission		$183		$104		$0		$4		$784	$0	$1,074		$1,074	$75,906
Schedule 90-P		$22		$0		$0		$2		$392	$0	$415		$415	$84,247
Schedules 91 & 95	$1,656			$0		$0	$98		$120		$1,874	$0	$7,796	$9,669	$17,260
Schedule 92		$20		$0		$0		$8		$5	$0	$33		$33	$247
Totals	$103,733	$34,313	$7,809	$900	$1,964	$550	$52,323	$5,111	$42,779	$12,515	$208,609	$53,390	$9,792	$271,791	$1,730,900

Source: PGE UE 283 Exhibit 1404, Cody, Page 2

PORTLAND GENERAL ELECTRIC – **UE 294**
RATE DESIGN INPUTS (CONTINUED)
SUMMARY - ALLOCATION OF 2016 COSTS TO RATE SCHEDULES ($000)

	Dist. Customer-Relate		Uncollectibles		Metering		Billing		Other Consumer		Subtotal				
Grouping	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Fixed Costs	Subtotal	Total Cost Allocations
Schedule 7	$92,850	$35	$7,371	$1	$5,675	$1	$53,490	$10	$37,455	$7	$196,842	$55		$196,897	$936,837
Schedule 15	$252		$61		$0		$140		$100		$553	$0	$1,706	$2,260	$3,606
Schedule 32	$8,921	$13,843	$200	$130	$909	$589	$3,263	$2,115	$4,042	$2,620	$17,335	$19,297		$36,632	$180,009
Schedule 38	$18	$402	$0	$0	$15	$110	$12	$86	$31	$230	$76	$827		$903	$5,538
Schedule 47	$21	$386	$0	$3	$3	$40	$16	$207	$16	$205	$56	$841		$897	$5,534
Schedule 49	$1	$354	$0	$4	$0	$31	$0	$96	$1	$295	$2	$779		$781	$14,306
Schedule 83															
Secondary	$329	$14,517	$4	$66	$55	$881	$60	$970	$255	$4,109	$703	$20,543		$21,246	$251,203
Schedule 85															
Secondary		$3,543		$48		$323		$283		$2,498	$0	$6,696		$6,696	
Primary		$516		$6		$37		$33		$290	$0	$882		$882	$185,851
Schedule 85 1-4 MW															
Secondary		$447		$3		$19		$17		$147	$0	$633		$633	
Primary		$280		$3		$19		$17		$149	$0	$468		$468	$72,499
Schedule 89 GT 4 MW															
Secondary		$18		$0		$0		$0		$13	$0	$32		$32	
Primary		$155		$0		$0		$5		$364	$0	$523		$523	
Subtransmission		$187		$0		$0		$1		$108	$0	$296		$296	$67,149
Schedule 90-P		$23		$0		$0		$0		$183	$0	$206		$206	$92,363
Schedules 91 & 95	$1,466			$0		$0	$244		$70		$1,780	$0	$5,592	$7,372	$13,450
Schedule 92		$18		$0		$0		$19		$3	$0	$40		$40	$259
Totals	$103,857	$34,727	$7,636	$263	$6,657	$2,051	$57,226	$3,859	$41,971	$11,221	$217,346	$52,120	$7,298	$276,765	$1,828,603

Source: PGE UE 294 Exhibit 1403, Cody, Page 2

CASE: UE 294
WITNESS: SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

OPENING TESTIMONY

June 15, 2015

Q. Please state your name, occupation, and business address.

A. My name is Suparna Bhattacharya. I am a Senior Economist in the Energy Rates Finance and Audits Division of the Public Utility Commission of Oregon (OPUC). My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97302.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/401.

Q. What is the purpose of your testimony?

A. This testimony focuses on two contested issues. First, it presents a recommended long run marginal generation cost model and shows the impact of the model's results across all rate schedules. Second, it reviews and provides recommendations on Portland General Electric's (PGE's or Company's) residential sales forecast methodology.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following Exhibits:

Exhibit Staff/401 Witness Qualification
Exhibit Staff/402 Wind-Direct Marginal Energy Cost
Exhibit Staff/403 Marginal Generation Cost with Wind Integration
Exhibit Staff/404 Marginal Energy Costs for each Schedule
Exhibit Staff/405 OPUC Data Responses for this testimony

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1, Marginal Generation Cost

Q. Please describe the company's approach to estimate marginal generation cost.

A. The Company's marginal generation cost study takes into account the renewable requirements of Renewable Portfolio Standard (RPS) policy by including wind in the generation model, and estimates weighted capacity cost and weighted marginal energy cost for the period 2016 through 2035, real levelized at 2016 dollars.

Specifically, the fixed cost of an "F" class simple cycle combustion turbine (SCCT) added with fixed gas cost transport[1] define the thermal capacity cost. Consistent with the Company's 2013 IRP, 12 percent reserve requirement is added to the SCCT thermal capacity cost. The fixed costs of a combined cycle combustion turbine (CCCT) that are in excess of SCCT fixed costs comprise the thermal marginal energy cost.

The derived thermal capacity cost is then combined with wind capacity cost and weighted capacity cost is the average of these two costs, weighted by RPS percentages for each year. To calculate wind capacity cost, PGE adds Bonneville Power Administration's (BPA's) Variable Energy Resource Balancing Service (VERBS) cost for integration service, thermal SCCT cost as well as fixed gas transportation cost. So, for 15 percent RPS requirement, weighted capacity cost can be expressed as:

[1] The November 2014 gas price forecast for the two hubs, Suma and AECO, is used for the cost study.

15% (wind capacity cost) + 85% (thermal capacity cost)

Weighted marginal energy cost is calculated by adding thermal marginal energy cost with wind plant cost[2], weighted by RPS percentages for each year. So, with 15 percent RPS, the Company's weighted marginal energy cost is: 15% (wind marginal energy cost) + 85% (thermal marginal energy cost).

Q. Does Staff agree with the Company's marginal generation cost approach?

A. No. Staff does not agree with the Company's method of adding thermal SCCT cost, fixed gas cost, and VERBS cost to calculate wind capacity cost, and subsequently taking a weighted average of wind capacity cost and thermal SCCT cost (based on RPS targets), to determine the weighted capacity cost. Staff's position is that any $/KW cost assigned to supplying wind power should be considered as an energy cost. In both dockets UE 215 and 262, Staff has objected to PGE's methodology to include wind as a portion of the capacity cost in the marginal general cost model (see UE 283 Staff/800, Bhattacharya/3, lines 6-9). For example, in UE 215, Staff's position was that any fixed costs beyond the minimum required to achieve a given level of peak demand (SCCT) should be classified as "energy" rather than "demand" costs (UE 215 Staff/1000, Ordonez/7, line 8).

Q. Please describe Staff's recommended marginal generation cost model for the current rate case- UE 294.

[2] Wind plant costs include capital carrying cost, fixed O&M, and land rents.

A. Staff's analysis follows from the review of the Company's original filing, accompanying workpapers, and the Company's responses to Staff's eleven data requests. To effectively incorporate wind power in the marginal generation cost model, Staff considers Port Westward 2 (PW2) as a flexible generating resource to offset random fluctuations associated with wind generation and derives the incremental energy cost associated with wind integration. The following steps describe Staff Exhibit 403, and details Staff's long run marginal generation cost model with wind integration for the time period 2016 through 2035.

1. Column C, shows Staff's thermal capacity cost in $kW-year. It is calculated as the sum of PGE's estimated thermal capacity SCCT cost (Column A) and SCCT fixed gas transport cost (Column B). Inclusion of fixed gas transport cost follows from the UE 215 rate case in which this was accepted by Staff.[3] Staff's thermal capacity cost is independent of RPS requirements and expressed as:
   (Thermal SCCT capacity cost + Fixed gas transport cost).
2. Column D, shows the flexible thermal resource cost, i.e., the cost of PW2 in $/KW-year. Staff calculated this cost based on PGE's response to Staff Data Request No. 434 (a).
3. Staff then estimated the incremental flexible resource cost by taking the difference between flexible thermal resource cost and thermal capacity

[3] See UE 215 Staff/1000-Ordonez/7, line 9.

SCCT cost. The incremental cost in $/KW-year as shown in Column E is: (PW2 cost + fixed gas cost) - (SCCT cost + fixed gas cost)

4. Column F, calculates the incremental cost in dollars for the flexible thermal resource capacity of 220 MW.
5. Column G, shows the incremental flexible resource per-wind-unit cost in $/MWh. Staff estimated this cost by considering incremental flexible resource cost over 2016 annual wind generation from Biglow and Tucannon wind farms. Staff collected the 2016 wind generation in MWh from the Company's response to OPUC Data Request No. 344 (a).
6. Column H, shows the wind-direct marginal energy cost. Staff estimated wind-direct energy cost in $/MWh using the Company's capital carrying costs, corrected land rent value (as provided in PGE's response to OPUC Data Request No. 319 (b)[4]), and the company's estimated fixed O&M costs. Staff Exhibit 402 reports the calculated wind direct marginal energy cost.
7. Column I, calculates the total wind marginal energy cost in $/MWh. Wind-direct marginal energy cost is added to incremental flexible resource per-wind-unit cost to generate total wind marginal energy cost.
8. Column J, includes the thermal marginal energy cost, as calculated by the Company, and Column K shows the RPS percentages.

[4] PGE's response to OPUC Date Request No. 319 (b) provides the corrected land rent value for the Tucannon wind farm in 2016$, and Staff used this corrected value to estimate wind-direct marginal energy cost. Staff's estimated wind-direct marginal energy cost is lower than that filed in the current docket.

9. Column L, is the weighted marginal energy cost in $/MWh. Staff derived weighted marginal energy cost based on RPS percentage requirements. So for 15% RPS, for example, weighted marginal cost is given as:
   15% (total wind marginal energy cost) + 85% (thermal marginal energy cost).
10. Finally, marginal capacity cost and weighted marginal energy costs were levelized in 2016 dollars.

Q. Please explain why Staff did not consider BPA VERBS cost in marginal generation cost analysis.

A. Staff's proposal considered PW2 as a flexible resource, assumed that PW2 has sufficient flexible thermal capacity to support PGE's entire annual wind generation, and marginal energy cost was derived in a similar fashion as described in the current testimony (UE 283 Staff/800-Bhattacharya/5-9).

Moreover, from OPUC Data Request No. 435, Staff understands that PGE's reliance on BPA services for wind integration, post September 2017, remains uncertain[5] , and that the Company will assess various least cost alternatives in the long run, including using its own flexible resources for integrating wind.

Finally, given that Staff has included the cost of the variable capacity resource in the wind integration model, including BPA VERBS might result in double counting of incremental energy cost associated with wind.

Q. Have you prepared an exhibit to show Staff's wind-direct marginal energy cost estimation?

---

[5] PGE elected 30/15 BPA VERBS schedule from October 1, 2015 through September 30, 2017

A. Yes. As explained above, Exhibit 402 shows the wind-direct marginal energy cost levelized in 2016$.

Q. Have you prepared an exhibit to show long run marginal generation cost with wind integration?

A. Yes. As mentioned above, Exhibit 403 shows the results derived from Staff's marginal generation cost study for the period 2016 through 2035.

Q. Have you prepared an exhibit to show the impact of wind power on marginal energy costs across rate schedules for the 2016 test year?

A. Yes. Exhibit 404 shows the marginal energy cost allocation for each rate schedules for the current test period 2016. Marginal energy cost allocation based on Staff's model is only illustrative, as PGE will update its marginal energy cost values with corrected wind plant cost in its reply testimony (see PGE response to OPUC Data Request No. 319 (b)).

Q. Have you prepared an exhibit to show the data responses utilized for Staff's marginal cost analysis?

A. Yes. Exhibit 405 attaches all data responses utilized for this testimony.

Q. What is Staff's recommendation to the Commission on marginal generation cost?

A. Staff recommends that the Commission adopt Staff's proposed long run marginal generation cost model and results, as presented in Exhibit 403. Staff's model appropriately assigns capacity and energy costs with wind integration, and marginal energy costs are effectively allocated across all rate schedules.

Issue 2, Residential Sales Forecast

Q. Please summarize the Company's sales forecast for residential customers.

A. The Company's sales forecast for the test year 2016 is 7625 thousand MWh. Forecast for the previous five years shows that the growth in energy sales is below one percent for the residential customers.

Q. Please give an overview of the Company's forecasting models that generated the 2016 sales forecast.

A. The Company has developed seven residential sales forecasting models (Schedule 7), based on dwelling and heating categories. The base sales forecast model is the product of use per customer (UPC) and the number of customers. For each residential customer group, the Company developed an econometric model for UPC. Specifically, the Company used linear regression models to quantify the relationship between UPC and the driving factors. The main set of inputs or explanatory variables include weather, seasonal, intervention, and economic drivers such as unemployment.

Finally, the base sales forecast for each group is adjusted to account for price and energy efficiency savings. The price effect adjusts the baseline sales forecast to account for the response to higher prices. First, the sales reduction is calculated by multiplying each group's real price change percent with the group's elasticity, and then this adjustment is deducted off of the base sales forecast to get price adjusted forecast. Energy efficiency adjustment captures the impact of Senate Bill 838 efficiency savings forecasted by Energy Trust of Oregon (ETO). The ETO's forecast for 2015 and 2016 energy efficiency measures is shaped into monthly incremental savings. The monthly incremental savings are aggregated into monthly cumulative energy savings and then allocated to each residential forecast group based on a historic pattern. The forecast group's cumulative energy efficiency savings are then removed from the group's price adjusted forecast.

The final load for Schedule 7 customers is the sum of total sales generated from each customer groups after adjusting for both price and energy efficiency. The final sales forecast for a customer group (r) with post estimation adjustments at a specific point of time (t) can be written in equation form as:

$Sales_t = \sum_{rt} [(UPC_{rt} \text{ X } Customers_{rt}) - Price\ Adjustment_{rt} - Energy\ Efficiency\ Adjustment_{rt}]$.

Q. Please explain Staff's approach to analyze the sales forecast for residential groups.

A. Staff has reviewed the Company's filing, workpapers, and responses to Staff's three data requests for this analysis. Staff's approach to evaluate the test year sales forecast involves the following steps:

a. Review of the Company's model and identification of issues

Staff first reviewed the Company's baseline energy use per customer regression models and sales forecast for each residential group (before price and energy efficiency adjustments) for the sample size January 2004 through October 2014.

The major concern, also raised in the last rate case (see UE 283 Exhibit Staff/300, Kaufman/12), is the methodology PGE used to evaluate the price impact on residential sales forecast. As mentioned above, the Company performs post-estimation adjustments to account for price effects. The base UPC models are thus, subject to omitted variable bias. The coefficients of the explanatory variables correlated to price also capture the price effect and with external price adjustments, forecasting models double count the effect of price.

PGE's response to OPUC Data Request No. 381 indicates that the Company calculated price elasticities for each residential group by considering regression model specifications used in the September 2013 load forecast model. Specifically, the Company developed an elasticity model by including price in the 2013 UPC regression models and incorporated the model estimates in current base models to forecast the 2016 demand under fixed and 10 percent increase in price. The percent change in sales generated from a 10 percent increase in price is then divided by 10 percent to get the elasticity numbers. These price elasticities are multiplied with the real price change and the resulting sales adjustment is removed from the base sales forecast to generate price-adjusted 2016 sales.

Staff finds that the 2013 UPC regression model specifications as well as the sample size, used to estimate elasticities, are much different from the current base model specifications. In other words, the 2013 regression models include many regression variables not included in the current base UPC regression models. Staff views the elasticity estimation process as an additional step and it is not required if price is directly included in the model.

b. Staff's Evaluation of the Price Issues

i. Model Specification and Estimation

To evaluate the aforementioned price issues, Staff developed alternate linear regression UPC models with price, seasonal, weather, economic indicators, and autoregressive terms as independent variables for the residential forecast groups. Staff used the Company's data provided through Eviews file SDEC 2014 (energy models) for regression analysis. Standard economic theory states (and is typically termed the "law of demand") that as price per kilowatt hour (KWh) rises, energy usage decreases. Staff estimated and analyzed the coefficient and significance of the price variable for all baseline models and also examined the consistency of other model parameters such as weather (included heating degree days (HDD) and cooling degree days (CDD)), seasonal and economic indicator (included unemployment) from a theoretical and statistical standpoint. Price coefficients for all models were of the "right" sign being negative and significant for most models. Model specifications of Staff's baseline UPC models were chosen based on the lowest Akaike Info Criterion (AIC) values and significance of the parameter estimates. Staff's final sales forecast for a customer group (r) with post estimation adjustment at a specific point of time (t) can be written in equation form as:

$Sales_t = \sum_{rt} [(UPC_{rt} \text{ X } Customers_{rt}) - \text{Energy Efficiency Adjustment}_{rt}]$.

ii. Model Performance

Second, to evaluate model performance, Staff measured how well model predictions fit out-of-sample data or the data that was not used to estimate the model's parameters. To perform this test, Staff first fitted the baseline UPC models to data from January 2004 through December 2013 (the in-sample-period), and treated January 2014 through October 2014 as the out-of-sample period.[6] Next, using the Company's customer count forecasts, baseline sales forecast for all residential groups is generated for the out-of-sample period. Finally, to estimate the effects of energy efficiency savings from SB 838, Staff generated incremental energy efficiency savings data for the out-of-sample period using the efficiency data provided as a response to OPUC Data Request No. 437. The energy savings were deducted off of the total sales from Staff's baseline model to generate the final sales forecast.

To measure model fit, Staff calculated the Root Mean Squared Error (RMSE)[7] for each residential forecast models and compared this accuracy measure across Staff's and the Company's final sales

[6] For robustness checks, Staff is still analyzing alternative out-of-sample time periods.
[7] RMSE is the square root of the average of the square of residuals, where residual is calculated as the difference between actual sales and Staff's predicted sales.

forecast. The lower the value of RMSE, the better is the model performance. Staff collected the Company's final sales forecast (price and energy efficiency adjusted) from the Company's filed workpaper, 5-SDEC14E Tables (2013 to 2016), for the out-of-sample period.

iii. Results

Results indicate that for most cases, Staff's models have lower RMSE and hence, perform better than the Company's sales forecast models. Table 1 compares the Staff's models with the Company's residential energy models based on RMSE.

Staff's proposal to include price directly in the econometric model is consistent with the standard industry practice. From the Company's response to OPUC Data Request No. 223, Staff identifies that only 5% (0%) of the total utilities surveyed in North America (West) account for price impact considering price variable outside the residential load forecasting models.

Table 1: Comparison of out-of-sample model performance

Actual sample: 2000M01 2013M12
Forecast sample: 2014M01 2014M10

Models	Staff	Company	Models	Staff	Company
ESFSH			**EMFSH**		
RMSE	5731	8415	RMSE	4306	9756
Price	(-)*	NA	Price	(-)*	NA
EMFNH			**ESFNH**		
RMSE	552	752	RMSE	10000	6749
Price	(-)	NA	Price	(-)	NA
EMHNH			**EMHSH**		
RMSE	77	179	RMSE	1325	2399
Price	(-)	NA	Price	(-)*	NA
EOTH					
RMSE	200	161			
Price	(-)**	NA			

*, **, and *** indicate 1%, 5%, and 10% significance levels
ESFH and EMFSH – space heat usage of single family and multi-family households
ESFNH and EMFNH – non-space heat usage of single family and multi-family households
EMHSH and EMHNH – non-space and space heat usage of mobile family households
EOTH – energy usage from residential others, mainly houseboats

Q. DOES STAFF HAVE ANY REVENUE ADJUSTMENTS?

A. Staff is still working on final sales forecast numbers and currently does not have any specific revenue requirement adjustments to propose. If a specific adjustment is determined after further review and analysis, Staff will propose an adjustment. However, it should be recalled that the Company's load forecast is not final until much later this year as the Company will be continuing to update certain data.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 294
WITNESS: SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualification Statement

June 15, 2015

WITNESS QUALIFICATIONS STATEMENT

NAME:	SUPARNA BHATTACHARYA
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	SENIOR ECONOMIST RATES, FINANCE & AUDIT
ADDRESS:	3930 FAIRVIEW INDUSTRIAL DR. SE SALEM, OREGON 97302-1166
EDUCATION:	Ph.D. Agricultural Economics University of Nebraska, Lincoln Specialization: Industrial Organization, Environmental & Natural Resource Economics, Production and Development Economics
	M.S. Agricultural Economics University of Nebraska, Lincoln Specialization: Statistics, Econometrics
	B.A. Economics Sambalpur University, India Specialization: Mathematical Economics
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since April, 2014, with my current position being a Senior Economist, in the Utility Program's Energy - Rates, Finance and Audit Division. My current responsibilities include reviewing sales forecast, long run marginal generation and transmission costs, decoupling mechanism, revenue requirements, and tariff verification.

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CASE: UE 294
WITNESS: SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support
Of Opening Testimony

June 15, 2015

STAFF EXHIBIT 402

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 15-036 IN UE 294

CASE: UE 294
WITNESS: SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 403

Exhibits in Support
Of Opening Testimony

June 15, 2015

STAFF EXHIBIT 403

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 15-036 IN UE 294

CASE: UE 294
WITNESS: SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 404

Exhibits in Support Of Opening Testimony

June 15, 2015

STAFF EXHIBIT 404

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 15-036 IN UE 294

CASE: UE 294
WITNESS: SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 405

Exhibits in Support
Of Opening Testimony

June 15, 2015

March 25, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 223
Dated March 12, 2015

Request:

Page three of the Company's UE 294 load forecast testimony (exhibit 1200) states that the price elasticity estimates used by the company are "consistent with price elasticities estimated for the Northwest". Please provide a citation or materials to support this claim.

Response:

Attachments 223-A and 223-B provide price elasticities in the Pacific Northwest region showing the reasonableness of PGE's price elasticities. Attachment 223-A was submitted by Western Public Agency Group (WPAG) as a data response in the 2003 Bonneville Power Administration (BPA) Rate Hearing. This study shows historic estimates of price elasticities on page 2 and 2003 price elasticities for WPAG utilities by customer class on page 3.[1] Attachment 223-B is a presentation summarizing the work of Joutz and Costello (2005) and contains regional elasticity estimates on pages 13 and 14.[2]

Attachment 223-C provides the Itron Benchmark study (2006) finding that PGE's price elasticities are within the bounds of industry estimates (listed on page 3 and on figures 3-4 of the attachment).

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[1] Attachment 223-A can be access online at: https://www.bpa.gov/power/lp/sn03/files/Parties_Data_Responses/
[2] Attachment 223-B can be access online at: http://www.iaee.org/documents/denver/Joutz.pdf

UE 294

Attachment 223-A

Provided in Electronic Format only

WPAG Price Elasticity Study
CR-WA-004A

UE 294

Attachment 223-B

Provided in Electronic Format only

Regional Short-Term Elasticity Consumption Models

UE 294

Attachment 223-C

Provided in Electronic Format only

Price Effects Benchmarking Study

April 1, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 319
Dated March 20, 2015

Request:

Please refer to LRMC gen_CONF file associated with the PGE Work Papers_1300_CONF.

a. Tab "Unit MC " shows marginal energy and capacity costs for the test year 2016. Column D of this spreadsheet shows BPA Variable Energy Resource Balancing Services (VERBS) costs in $KW-year from 2016 - 2035. Are these costs based on BPA's 30/15 committed scheduling? Please provide the electronic spreadsheet (with cell references and formulae intact) showing the calculation of BPA VERBS cost for the test year 2016.

b. Tab "Wind Plant 2016" shows the allocated costs of the Tucannon River Farm. Column M calculates Variable O&M cost of the wind farm based on land rents. Please explain the reasons for considering land rents as variable O&M cost. Please provide an electronic spreadsheet (with cell formulae intact) showing the calculation of the land rents, as reported in Row 31 of tab "Wind Plant 2016".

Response:

a. The BPA VERBS costs included in the cost study are based on BPA's 30/60 Committed Scheduling. See page 2 of Attachment 319-A for the total price of $1.20 per kW-month as provided by BPA. The calculation in Column D as referenced in this request is used to express the amount on in dollars per kW-year and escalates the amount to the appropriate year.

b. Land rents are considered variable O&M costs because the contracts with landowners specify that PGE will pay rents based on the actual production of the Tucannon River Wind Farm. Upon review, it appears that the land rent figure used in PGE's initial filing was not updated from the generation marginal cost results used in PGE's last general rate case, Docket No. UE 283. The land rent cost in 2016 dollars should be $3.12/MWh. PGE expects to correct these costs in its reply testimony. For the land rent calculation, please refer to the MONET output file "#TucannonLandOwnerRoyalty_2015_FACalc.xlsx", worksheet "Tucannon".

   The file is located in the "Volume 7 – Wind\Tucannon\Royalty Payments" directory of the Minimum Filing Requirements (MFR) documentation filed on February 27, 2015, in Docket No. UE 294.

UE 294

Attachment 319-A

Provided in Electronic Format only

April 13, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 344
Dated March 31, 2015

Request:

Please refer to "Biglow & Tucannon 2014" tab of the confidential attachment "OPUC_DR_212_Attach A_CONF.xlsx" that was provided by PGE in response to OPUC Data Request No. 212.

a. Column Z of Row 15 shows VERBS cost in $/MWh for the year 2014. Please provide the electronic worksheet (with cell references and formulae intact) showing the calculation of the VERBS cost in $/MWh for the years 2015 and 2016.

b. The VERBS cost in $/MWh, shown in Row 15 considers wind generation from PGE owned Biglow and Tucannon wind farms (Rows 12 and 13). Please explain why PGE is not including wind power from contracts- Vansycle Wind and Klondike Wind for estimating the VERBS cost. Are these wind farms located in BPA's balancing authority?

Response:

(a) Attachment 344-A contains the total annual 30/15 BPA VERBS rate converted to $/MWh using PGE's 2015 General Rate Case (GRC) final MONET forecasted generation and PGE's 2016 GRC April 1 update MONET forecasted generation.

BPA began offering VERBS as a tariffed service in October 2009. Beginning in 2009, PGE purchased the VERBS 30/60 committed scheduling option. Beginning in 2012, BPA offered a committed intra hour (CIH) pilot program for VERBS customers. The

CIH pilot required participants to schedule wind using a 30/30 scheduling metric and provided participants with credit to their regular VERBS expenses. PGE participated in the CIH pilot during 2012 through the end of the pilot in 2013. After the end of the CIH pilot, PGE returned to using the VERBS 30/60 committed scheduling. For the BPA rate period beginning in October 2015, PGE has elected to participate in VERBS 30/15 committed scheduling.

Attachment 344-A is confidential and subject to Protective Order No. 15-036.

(b) The Vansycle and Klondike II wind facilities are physically located within the BPA control area. PGE does not include Vansycle and Klondike II for estimating the VERBS cost because PGE does not purchase VERBS for either facility. For the Vansycle and Klondike II power purchase agreements (PPAs), PGE receives a flat hourly delivery from the owners of the facilities and does not purchase VERBS for these facilities.

UE 294

Attachment 344-A

Provided in Electronic Format only

Confidential and Subject to Protective Order No. 15-036

VERBS Cost Estimate

April 21, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 381
Dated April 9, 2015

Request:

Please refer to the PGE Workpapers_1200_CONF related to load forecast:

a. **Regression estimates for the base (B) models are reported in Final Models of the 12-Regressions_CONF. Regression estimates for the price-effect (P) models are shown in the SSEP13 price elasticity model specifications_CONF.pdf file of the 19-Price Elasticity Work Papers_CONF. Please explain in detail and provide all statistical tests performed for considering different time periods for B and P forecast models. Please provide an explanation that separately addresses Residential, Commercial and Industrial classes.**

b. **Pages 18-22 of the SSEP13_Model_Price_Elasticity_CONF.pdf file in the folder 19-Price Elasticity Work Papers_CONF show SAS codes that calculate residential use per customer by dwelling and heating type using regression coefficients generated from the P model (shown in Eviews file "ssep2013_price_elasticity.wf1" and pdf file SSEP13 price elasticity model specifications_CONF.pdf). SAS codes show that some independent variables of the P model are not included for calculating energy use per customer. Please provide the reasons for excluding some explanatory variables from the energy use per customer calculation?**

Response:

a. PGE performed its most recent price elasticity study in the third quarter of 2013. It is provided with the initial filing as part of confidential work papers in folder 19- Price Elasticity Work Papers. The elasticities in the price change adjustment model ("P" forecast) were calculated utilizing energy regression model specifications consistent with those used in the September 2013 load forecast model. PGE's typical forecast process does not include an update to the price elasticity study. PGE uses this approach since it has found price elasticities to be stable over time; therefore the elasticity study update is only performed periodically. The price elasticity study calculates elasticities, not models for use in the price adjustment model; therefore there are no tests between equations used in the price elasticity study and future forecasts. All classes are subject to the same approach.

b. As explained above the price elasticity study utilized regression models with explanatory variables consistent with forecast models used at the time the study was performed.

May 8, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 434
Dated April 24, 2015

Request:

Please refer to UE 294/PGE/1400 Macfarlane - Werner confidential work paper "LRMC gen_CONF.xlsx".

a. **Please provide a modified version of this work paper with the combined cycle combustion turbine inputs and any other pertinent data replaced with Port Westward 2 inputs.**
b. **Please provide the worksheet that shows the marginal capacity cost of Port Westward 2 in $/KW-year used in the marginal generation cost study in Docket UE 283.**

Response:

a. Please see Confidential Attachment 434-A for the modified version of the requested work paper. In preparing this response, PGE replaced the following SCCT inputs with estimates for Port Westward 2:

Economic life, salvage value, capital costs, installed capacity, fixed O&M, variable O&M, heat rate, and availability factor. PGE left other inputs and assumptions unchanged.

In addition, VERBS[1] costs are removed.

[1] Variable Energy Resource Balancing Service

b. PGE did not use the marginal capacity cost of Port Westward 2 in its marginal generation cost study in Docket No. UE 283. However, PGE provided a response to a similar data request in Docket No. UE 283 (i.e., OPUC Data Request No. 299), provided as Attachment 434-B and Confidential Attachment 434-C.

Attachments 434-A and 434-C are confidential and subject to Protective Order No. 15-036.

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UE 294

Attachment 434-A

Provided in Electronic Format only

Confidential and subject to Protective Order No. 15-036

Generation Marginal Cost Study with PW2 Inputs

UE 294

Attachment 434-B

Provided in Electronic Format only

UE 283 PGE Response to OPUC Data Request No. 299

UE 294

Attachment 434-C

Provided in Electronic Format only

Confidential and subject to Protective Order No. 15-036

UE 283 PGE Response to OPUC Data Request No. 299
Attachment 299-A

May 8, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 435
Dated April 24, 2015

Request:

Please refer to tab "Unit MC" of the UE 294/PGE/1400 Macfarlane - Werner confidential work paper "LRMC gen_CONF.xlsx". Please explain PGE's plans on self-integrating wind in the next ten years.

Response:

PGE continues to implement its step-wise approach towards full self-integration of wind. By electing Bonneville Power Administration's (BPA) 30/15 committed scheduling VERBS[1] rate, PGE moved a step closer to full self-integration. Beginning October 1, 2015, PGE will use its thermal and hydro resources to manage the intra-hour variability of its wind resources on a 15-minute basis (i.e., 15-minute schedule-to-schedule). In order to fully self-integrate its wind resources, PGE would need to also manage the moment-to-moment and within-schedule changes in wind (just as it presently does for load).[2] PGE's plans for full self-integration are contingent on several factors.

- PGE's next opportunity to elect full self-integration of its entire wind fleet is the next BPA rate period, which begins October 1, 2017. As PGE nears the VERBS election window (the timing of which BPA has not yet established) it will assess its alternatives and identify the least-cost and least-risk option for integrating wind resources (and other variable energy resources, if applicable).

[1] Variable Energy Resource Balancing Service
[2] BPA currently provides moment-to-moment regulation service and following service needed to integrate the difference between the 15-minute schedule and actual output of a facility.

- PGE is presently working to prepare to participate in a within-hour market. Rather than relying solely on PGE's system resources for full self-integration, PGE's participation in a within hour market could prove to be a cost-effective method to assist PGE in fully self-integrating variable energy resources. PGE is presently assessing its within-hour market options, including the efforts of the Northwest Power Pool (NWPP) Market Assessment and Coordination Committee (MC) Initiative and the California Independent System Operator Energy Imbalance Market (CAISO EIM). PGE anticipates sharing the results of its assessment during the fourth quarter of 2015. In addition to the assessment described above, PGE is implementing several projects (e.g., software additions and metering upgrades) that are needed to participate in an automated within-hour market.

- PGE is developing internal tools used for wind forecasting and scheduling. This effort will produce a robust wind forecast necessary for PGE to reliably manage its portfolio under full self-integration.

PGE will continue to develop its internal tools for wind forecasting and scheduling and analyze options offered by BPA and regional within-hour markets as we approach the 2017 selection window.

With respect to PGE's generation marginal cost study in Docket No. UE 283, PGE expressed that VERBS from BPA is an objective, verifiable cost that PGE and others currently incur to integrate wind resources (see PGE Exhibit 2100 in Docket No. UE 283). PGE used VERBS in the generation marginal cost study in this docket for the same reason. In addition, the parties stipulated to use VERBS in the marginal cost study in UE 283 and final prices reflected that agreement.

May 8, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 437
Dated April 27, 2015

<u>Request:</u>

Please provide the load forecast energy efficiency work papers showing the incremental and cumulative energy efficiency adjustments by forecast group from the final load forecasts filed in UE-283 *(for 2015)*, UE-262 *(for 2014*), and Annual Update Tariff filings for the prompt years 2009 to 2013.

<u>Response:</u>

Attachment 437-A provides PGE's forecasted cumulative monthly energy efficiency savings in megawatt-hours (MWh) by forecast group and by forecast vintage for 2009 to 2015. PGE calculates the cumulative forecasted energy efficiency from the forecasted monthly incremental savings prior to the forecast group allocation; therefore the forecasted incremental savings are only available by aggregated residential, commercial and manufacturing groupings.

Attachment 437-B shows the incremental and cumulative monthly energy efficiency savings by forecast for residential, commercial and manufacturing prior to the allocation. The forecasted cumulative energy efficiency savings is allocated to forecast groups using the forecast group share of energy deliveries for their respective residential, commercial and manufacturing groups.

Attachments 437-C through 437-I contain the SAS code for the calculation of the incremental and cumulative energy efficiency for each provided forecast.

UE 294

Attachment 437-A

Provided in Electronic Format only

PGE Cumulative Monthly Energy Efficiency Savings in MWh by Forecast Group for 2009-2015

UE 294

Attachment 437-B

Provided in Electronic Format only

PGE Incremental and Cumulative Monthly Energy Efficiency Savings in MWh by Residential, Commercial and Manufacturing Groups for 2009-2015 forecasts

UE 294

Attachment 437-C

Provided in Electronic Format only

SAS Code

UE 294

Attachment 437-D

Provided in Electronic Format only

SAS Code

UE 294

Attachment 437-E

Provided in Electronic Format only

SAS Code

UE 294

Attachment 437-F

Provided in Electronic Format only

SAS Code

UE 294

Attachment 437-G

Provided in Electronic Format only

SAS Code

UE 294

Attachment 437-H

Provided in Electronic Format only

SAS Code

UE 294

Attachment 437-I

Provided in Electronic Format only

SAS Code

CASE: UE 294
WITNESS: ROBERT FONNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

OPENING TESTIMONY

JUNE 15, 2015

Q. Please state your name, occupation, and business address.

A. My name is Robert Fonner. I am employed as a Senior Economist in the Utility Program's Energy - Rates, Finance and Audit Division. My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97302.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/501.

Q. What is the purpose of your testimony?

A. This testimony presents my analysis and recommendations regarding Portland General Electric's (PGE's or Company's) non-residential customer sales forecast and marginal customer cost study.

Q. Which issues remain contested for which you are responsible?

A. The non-residential customer sales forecast and customer marginal cost remain contested. I am not responsible for any of the issues included in the partial stipulation.

Q. Are you investigating any other issues as a part of this general rate case?

A. Yes. Staff is also looking into the cost of replacing smart meters and the monthly costs to read the replacement meter. However, Staff's analysis of this issue is still in the discovery phase and Staff does not have an adjustment at this time.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

Exhibit Staff/501 Witness Qualification

Exhibit Staff/502 Data Request Responses
Exhibit Staff/503 Forecast of paperless billing shares
Exhibit Staff/504 Customer Marginal Cost Adjustment

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Please summarize Staff's analysis and recommendations regarding each issue identified above.

A. A summary of my analysis follows:

1. Non-residential Customer Sales and Load Forecast: After reviewing PGE's forecasting methodology, staff concludes that price effects are not effectively captured by the Company's current modeling strategy. Staff proposes dropping the price adjustment from the forecast in this rate case. Moving forward, Staff will work with PGE to develop a method that more appropriately captures the effects of price in the non-residential sales forecast.

   Staff also reviewed PGE's treatment of energy efficiency in the forecasting models. Staff believes that PGE's current methodology double-counts energy efficiency effects. Staff proposes alternative methodologies for incorporating energy efficiency and will work with the Company to develop and test these models.

Removing the external price adjustment from the Company's non-residential customer forecasting model, as is being recommended by Staff in the current rate case, will lead to an adjustment to test year revenues. The magnitude of the revenue adjustment will depend on the PGE's final base forecasting model.

2. Customer Marginal Cost: Staff proposes that PGE's marginal cost study should incorporate trends in the adoption of paperless billing. This adjustment shifts some costs from residential to non-residential customers.

   PGE's customer marginal cost study includes a number of new cost categories that were not included in previous rate cases. Staff does not object to these new cost categories in the current rate case, with the caveat that a review of the suitability of the inclusion of these costs is ongoing.

3. Mailing Expense Forecast: Staff's initial findings include a projection that the Company will send fewer mailings in 2016 compared to 2014 due to the rate at which paperless billing is adopted. However, mailing expense may increase. Analysis of this issue is ongoing.

Issue 1, NON-RESIDENTIAL CUSTOMER SALES AND LOAD FORECAST

PURPOSE OF SALES AND LOAD FORECAST

Q. What is the non-residential load forecast used for in this rate case?

A. The forecast is fed into marginal cost studies that allocate the Company's revenue requirement among schedules. The forecast is also used to determine the set of tariff rates that will allow the Company the opportunity to collect its authorized revenue requirement.

Q. How should the non-residential sales forecast be judged?

A. The forecasting method should be selected according to the following criteria:

1. The forecast should be chosen to minimize weather adjusted forecast error variance and minimize forecast bias in back-casting and out-of-sample prediction. Forecast error variance is the sum of the squared difference of the forecast and weather adjusted actual sales. Forecast bias is the expected value of the difference between the forecast and the weather adjusted actual values, and
2. Forecast assumptions should be consistent with economic theory and the current economic environment relevant to the forecast. Both of these measures require comparing two or more forecast models.

THE COMPANY'S FORECAST AND METHODOLOGY

Q. Please describe the Company's non-residential customer sales and load forecast.

A. PGE's forecasting methodology is a three step process. First, a base econometric model is estimated (i.e. base forecast) to determine the relationship between loads and load determinants (e.g. economic and weather variables). Second, the base forecast is adjusted for customer price response to the Company's requested rate increase. The price adjustment is based on price elasticities estimated in auxiliary econometric models. Third, the Company further adjusts the forecast for incremental energy efficiency projected by the Energy Trust of Oregon (ETO). PGE develops individual forecasts for specific industry groups and then allocates the forecasts to rate schedules using historical shares[1].

BASE FORECAST

Q. Please describe PGE's development of the non-residential base model since UE 283.

A. In 2014, PGE hired a third-party consultant to review their forecasting methodology. The review led PGE to modify several of its non-residential base model specifications. Specifically, PGE modified the time periods and the economic variables used in estimation of the base model.

Q. Does Staff have concerns with PGE's methodology for the non-residential customer base forecast?

A. Staff does not have major concerns with the Company's non-residential base forecast and is not proposing base forecast changes in UE 294. However,

[1] The industry group forecasts are first allocated by voltage class and then are allocated by rate schedule. See PGE's response to Staff Data Request No. 359a, attached as Exhibit Fonner/502.

future iterations of the base forecast may be improved in two basic ways. First, the forecasts would benefit from the use of explanatory data specific to the Company's service territory (i.e. county level data). Second, an integrated modeling approach that jointly considers important load determinants in a single model, without outboard adjustments, would improve the base forecast modeling methodology.

PRICE ADJUSTMENT

Q. Please describe PGE's methodology for incorporating price effects into the non-residential customer forecast.

A. PGE's current forecasting methodology accounts for customer responses to price changes outside of the base econometric model. Specifically, the Company estimates another set of econometric models to estimate the relationship between price and the quantity of electricity demanded by customers (i.e. price elasticity of demand). The base econometric models and the price elasticity econometric models use the same dependent variables and include similar economic drivers. The main difference between the base models and the price models is that the auxiliary models include a price variable, calculated as revenue divided by KWh.

The purpose of the price econometric models is to estimate price coefficients that are then used to calculate price elasticities (i.e the typical customer response to a price change) for each forecast group. The estimated price elasticities are then applied to the base model forecast to derive the price-adjusted forecast.

Q. Is PGE's treatment of price consistent with standard practice of the utility industry?

A. Accounting for price effects outside of the base forecast is not in line with standard industry practices. In 2014, the Company hired a third-party consultant to review their forecasting methodology. The results of this review were included in the UE 294 workpapers. The third party consultant surveyed 117 utility companies in the United States and Mexico about their forecasting methodologies. Forty percent of the electricity utilities surveyed did not account for price response at all in their commercial load forecasts and 46 percent of those companies did not account for price in their industrial load forecasts. The survey then asked electric utilities how they account for price responses in their forecasting models. Only 11 percent of respondents who include price in their industrial forecasting models did so outside the base model (i.e. the method used by PGE). Thirteen percent of respondents who include price in their commercial forecasting models did so outside the base model. It is Staff's position that PGE should align with industry standards, either by excluding price effects from their forecasting process or by appropriately accounting for price within their base econometric models.

Q. Does Staff have concerns with PGE's methodology for incorporating price effects into the forecast?

A. Staff has two general concerns with the Company's method for incorporating price effects in the commercial and industrial forecasts. First, the method double counts price effects. Second, the price econometric models perform poorly in terms of estimating price coefficients.

Double counting of price effects results from accounting for price effects outside the base econometric model. The load actuals used in base model estimation include responses to past price changes, and forecasts will thus reflect a background level of price response. Furthermore, price responses may be partially captured through the variables that are included in the base models. For example, the high (close to one) R-squared statistics reported for the Company's base models indicate that the models explain a high degree of the load variation. While it is possible that price response is completely contained within the unexplained variation, it is more likely that the estimated coefficients of explanatory variables that are correlated with price capture a portion of the price response[2].

Staff's second concern with the Company's treatment of price is the poor performance of the price econometric models. These models are estimated specifically to derive a price coefficient that can be used to calculate price elasticity (i.e. the percent change in load associated with a given percent change in price) for each forecast group. Thus, the usefulness of the auxiliary econometric models depends on their ability to produce a reliable estimated price coefficient. However, the Company's auxiliary price models fail to meet this standard. Four of the 17 total industrial and commercial auxiliary price

[2] For example, there is a weak positive (0.2) correlation between average real price and non-manufacturing employment, an explanatory variable used in the base models.

regressions produce statistically significant[3] estimated price coefficients. In other words, thirteen of the estimated price coefficients are not statistically different from zero. Additionally, three of the regressions produce positive estimated price coefficients[4]. This inconsistency leads Staff to question the validity of the Company's auxiliary price regressions.

Q. What is Staff's recommendation regarding PGE's treatment of price effects in the non-residential forecasts?

A. Staff recommends that PGE remove the external price adjustment from its Commercial and Industrial forecasts. This approach would increase the Company's preliminary 2016 forecast by 7,859 MWh (0.11%) and 6,225 MWh (0.13%), in the commercial and industrial schedules, respectively.

Q. How might price be effectively incorporated into PGE's future non-residential customer forecasts?

Staff believes the Company should explore alternate techniques for capturing price responses in their forecasting models. First, Staff recommends the Company develop an improved price variable based on the historical marginal prices faced by PGE customers[5]. In the current models, PGE approximates price as revenues divided by quantity of electricity. This variable includes fixed customer charges and does not accurately represent the effective price faced by customers. Second, the Company should explore model specifications that

[3] At the .05 level.
[4] The Company assumes a price elasticity of zero in these cases.
[5] This can be done with past tariffs and Company databases.

integrate marginal price into the base econometric models and address the double counting issue raised previously.

ENERGY EFFICIENCY ADJUSTMENT

Q. Please describe PGE's methodology for incorporating energy efficiency (EE) into the non-residential customer forecast.

A. From the base forecast, PGE subtracts the expected future EE forecasted by the ETO. The period of the EE subtracted is cumulative from the end of the data used to estimate the base model to through the 2016 test year. ETO produces separate EE forecasts for industrial and commercial customers. PGE then allocates ETO's forecast into industry groups to calculate the base forecast EE adjustment. The EE adjustment is then subtracted from the Company's price adjusted forecast to get the Company's final forecast by forecast group.

Q. Does Staff have concerns with PGE's methodology for incorporating energy efficiency into the forecast?

A. Yes, PGE's energy efficiency adjustment double counts as the base forecast includes a background level of energy efficiency. Furthermore, PGE is unable to effectively evaluate the accuracy of its EE adjustment under its current method.

Q. How might energy efficiency be effectively incorporated into PGE's future non-residential customer forecasts?

A. Staff recommends that the Company explore alternative methods for incorporating EE into the forecast. The suggested methods require, as an input, historical EE data at the forecast group (i.e. industry type) level. The ETO maintains a database of achieved EE at the project level, identified by business type, completion date, and other project characteristics. This data can be acquired by PGE and aggregated by month and forecast group[6] to construct monthly historical EE by forecast group.

With historical EE by forecast group, at least three alternate methods for EE adjustment are possible. First, the forecast-level EE actuals can be inserted into the base econometric model directly. This specification would include a coefficient representing the proportion of forecasted EE that is actually implemented. A second possible method is to add cumulative historical EE to historical loads (i.e. base model dependent variable) before the econometric model is estimated. Using the constructed dependent variable, the econometric model produces a forecast of loads in the absence of ETO energy efficiency. Cumulative past actual and projected EE is then subtracted from the econometric forecast to produce the EE adjusted forecast.

Finally, the historical EE series can be used to measure error and bias in past EE forecasts. This will help the Company verify the accuracy of allocated ETO forecasts and to compare the allocated ETO forecast with alternative EE forecasting methods.

Q. What is Staff's recommendation regarding PGE's treatment of EE effects?

[6] Includes both Senate Bills (SBs) 838 and 1149 EE. Thus the forecast data would differ from PGE's current method that only considers SB 838 EE.

A. Staff supports PGE's current method of EE adjustment in the current rate case, contingent on the Company's willingness to work with Staff in developing improved EE adjust methods, including those mentioned above.

Issue 2, CUSTOMER MARGINAL COST

Q. Please summarize Staff's analysis of PGE's customer marginal cost study.

A. Staff analyzed PGE's marginal cost studies including Macfarlane-Werner Workpaper "2016 TY - Customer Marginal Cost - Work papers.xlsx". The cost allocations assume 2014 levels of paper and paperless billing[7]. Staff recommends that the Company calculate marginal customer costs based on the expected relative levels of paper and paperless billing in 2016. Staff estimated the projected ratio of paper to paperless billing by calculating the average annual ratio change from 2005 to 2014 and then assuming that the ratio grows at that pace through 2016. Exhibit 503 shows Staff's projected 2016 paperless to total bills ratios by rate schedule and Exhibit 504 shows the resulting customer marginal cost by rate schedule. The adjustment causes a minor shift of marginal customer cost allocations among rate schedules.

Q. Were any cost categories added to the study since UE 283?

A. Yes in the Company's response to Staff Data Request 354, PGE states that it included new cost categories in the Marginal Customer Cost study[8]. PGE has communicated to Staff that these cost categories were erroneously omitted from previous rate-case marginal cost studies. Staff accepts the inclusion of these new cost categories in UE 294, but continues to evaluate the newly included cost categories.

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[7] PGE's marginal cost study allocates to rate schedules based on 2014 actuals but the costs reflect the 2016. The mailing costs assumed in the 2016 budget are analyzed later in this testimony.

[8] See Exhibit Staff/502. The Marginal Customer Cost study was provided in UE 294/PGE/1300 Macfarlane-Werner Workpaper "2016 TY - Customer Marginal Cost - Work papers.xlsx".

Issue 3, MAILING BUDGET

Q. Please summarize Staff's analysis of PGE's mailing expense forecast.

A. Staff reviewed PGE's mailing counts for years 2009-2014. This data was then used to project the number of 2015 and 2016 mailings under the assumption that the future mailings change at the 2009-2014 average rate. PGE's 2009-2014 actual mailing counts and Staff's projections for 2015 and 2016 are in table 501.

Table 501

Year	Paper bills, notices and letters*	Percent change**	Other mailings	Percent change
2009	11,086,753		1,681,142	
2010	11,022,067	-0.58%	1,522,873	-9.41%
2011	10,872,156	-1.36%	1,681,588	10.42%
2012	10,638,644	-2.15%	1,100,819	-34.54%
2013	10,372,409	-2.50%	1,161,704	5.53%
2014	10,376,763	0.04%	1,263,368	8.75%
2015	10,240,788	-1.31%	1,214,736	-3.85%
2016	10,106,595	-1.31%	1,167,976	-3.85%

* From PGE's response to SDR 466
** 2015 and 2015 calculated as the average of 2009-2014

Staff projects the Company will send 270,168 fewer bills, notices and letters and 95,392 fewer other mailings in 2016 compared to 2014. The Company's 2014 weighted average cost to send bills, notices, and letters is $0.46[9]. Assuming mailing expenses remain at 2014 levels, Staff's projected decrease in mailings would reduce PGE's mailing costs by $169,847[10]. However, PGE reported that postage costs increased in June 2015[11].

The Company's mailing expenses are largely captured in cost categories RC727 (Printing and Automated Mail Services) and RC729 (Business Services Group). The Company's 2016 budget assumes that RC727 and RC729 change by ($428,843) and $83,529, respectively, compared to 2014 actuals[12]. Combined, this represents a projected 7% decline in these cost categories from 2014 to 2016.

Q. Has Staff completed its analysis of PGE's mailing expenses?

A. No. Staff's analysis of mailing expenses is ongoing.

Q. Will Staff have an adjustment for postage for its next round of testimony?

A. Perhaps as we continue to investigate this issue, the result may be a proposed adjustment for reduction in postage due to electronic billing.

Q. Does this conclude your testimony?

A. Yes.

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[9] See PGE's response to Staff Data Request No. 463, attached as Exhibit Fonner/502.
[10] This also assumes that other billings cost the same as bills, notices and letters.
[11] See PGE's response to Staff Data Request No. 466, attached as Exhibit Fonner/502.
[12] See UE 294/PGE/1300 Macfarlane-Werner Workpaper "2016 TY - Customer Marginal Cost - Work papers.xlsx".

CASE: UE 294
WITNESS: ROBERT FONNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualification Statement

June 15, 2015

WITNESS QUALIFICATION STATEMENT

NAME:	ROBERT FONNER
EMPLOYER:	PUBLIC UTIILTY COMMISSION OF OREGON
TITLE:	SENIOR ECONOMIST ENERGY RATES, FINANCE & AUDIT DIVISION
ADDRESS:	3930 FAIRVIEW INDUSTRIAL DR SE SALEM OREGON 97302
EDUCATION:	Bachelor of Arts, Environmental Studies and Economics, University of Colorado, 2004 Master of Science, Natural Resource Economics, Oregon State University, 2008 Doctor of Philosophy, Economics, University of New Mexico, 2014
EXPERIENCE:	I have been employed by the Public Utility Commission since June 2014, with my current position being a Senior Economist, in the Utility Program's Energy - Rates, Finance and Audit Division. My current responsibilities include analysis and technical support for rate, finance, and audit related proceedings, with an emphasis on forecasting and marginal cost studies. Prior to working for the OPUC I served as an Instructor and Research Assistant in the Economics Department at the University of New Mexico. I have taught courses in Microeconomics, Macroeconomics, and the Economics of Regulation. I served as a Teaching Assistant for courses in forecasting and graduate-level econometrics. Before my time at the University of New Mexico, I worked as an Economist for Cardno ENTRIX environmental consultants from 2007 to 2009. I served as a Research Assistant for the Coastal Oregon Marine Experiment Station from 2004 to 2006.

CASE: UE 294
WITNESS: ROBERT FONNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 502

Exhibits in Support
Of Opening Testimony

June 15, 2015

April 17, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 354
Dated April 3, 2015

Request:

Were additional cost categories included in the customer marginal cost study compared to the customer cost study in the Company's previous rate case (UE 283)? If so, for each new cost category included, please describe in detail the Company's rationale for including the cost and explain why the cost category was not included in the marginal customer cost study in the previous rate case.

Response:

Yes. Attachment 354-A provides the requested information.

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UE 294

Attachment 354-A

Provided in Electronic Format only

Rationale for CMC Categories

Account	RC	Description	In 2015 Budget	In 2015 Study	In 2016 Study	Explanation for Inclusion in 2016 Study	Explanation for Exclusion in 2015 Study
9020001	753	Enterprise Telecommunications	Yes	No	Yes	These costs are a result of increasing lease costs associated with upgrades to the Advanced Metering Infrastructure (AMI) network required for PGE to serve a growing customer base.	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9020001	999	Corporate Transfers	Yes	No	Yes	These costs represent account entries such as labor loadings, service provider allocations, accruals, amortization of prepaid costs, etc. that are necessary for accurate accounting. These costs are included in the study because they are directly tied to the costs necessary to perform the tasks contained in the functional categories in each customer service account.	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9030001	304	VP Customer Svc Operations	Yes	No	Yes	These costs represent the salary of the VP of customer service, whose role is to support the operations of customer service operations.	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9030001	361	Corporate Training	Yes	No	Yes	These costs are a result of trainings given to PGE employees in the customer service area. They are designed to help PGE employees administer quality and effective customer service.	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9030001	435	Special Attention Operations	Yes	No	Yes	These costs are a result of the work required for PGE to resolve customer disputes at the OPUC, facilitate Federal/State mandated low-income programs, and administer PGE's Medical Certificate program. These customer service functions are mandated by law.	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9030001	472	CSO Performance Management	No	No	Yes	These costs are a result of developing and tracking performance metrics, forecasting and scheduling services, and performing quality assurance for customer service.	These costs were not planned for in the 2015 budget.
9030001	555	VP Cust Strategy & Bus Devel	Yes	No	Yes	These costs represent the salary of the VP of customer strategy prorated to account for tasks performed in support of customer service operations.	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9030001	591	SVP Cust Service/Trans/Distrib	Yes	No	Yes	These costs represent the salary of the SVP of customer service prorated to account for tasks performed in support of customer service operations.	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9030001	737	IT Governance	Yes	No	Yes	These costs are a result of licensing and maintenance support of software and hardware for IT through negotiation and settlement of vendor contracts, which are necessary to perform the tasks required for customer service.	These costs should have been included in the 2015 study as they are necessary for customer service operations.

9030001	753	Enterprise Telecommunications	Yes	No	Yes	These costs are a result of the engineering required to maintain PGE's telecommunication network, which is necessary to perform the tasks required for customer service	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9030001	754	Network Services	Yes	No	Yes	These costs are a result of maintenance required to provide stability and reliability of PGE's network and security IT infrastructure services. These services are necessary to perform the tasks required for customer service.	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9030001	757	IT Applications	Yes	No	Yes	These costs are a result of the development and support of IT applications for customer service.	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9030001	915	Corporate Communications	Yes	No	Yes	These costs are a result of supporting and managing data inquiries related to customer data, conducting load research studies, and managing customer program evaluations. These are all tasks necessary for customer service operations	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9030001	999	Corporate Transfers	Yes	No	Yes	These costs represent account entries such as labor loadings, service provider allocations, accruals, amortization of prepaid costs, etc. that are necessary for accurate accounting. These costs are included in the study because they are directly tied to the costs necessary to perform the tasks contained in the functional categories in each customer service account.	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9050001	999	Corporate Transfers	Yes	No	Yes	These costs represent account entries such as labor loadings, service provider allocations, accruals, amortization of prepaid costs, etc. that are necessary for accurate accounting. These costs are included in the study because they are directly tied to the costs necessary to perform the tasks contained in the functional categories in each customer service account.	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9080001	534	Customer Training & Education	Yes	No	Yes	These costs are a result of providing free educational seminars, webinars, and online trainings on energy-efficiency behaviors and technologies for business customers.	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9080001	555	VP Cust Strategy & Bus Devel	Yes	No	Yes	These costs represent the salary of the VP of customer strategy prorated to account for tasks performed in support of customer service operations.	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9080001	753	Enterprise Telecommunications	Yes	No	Yes	These costs are a result of increasing lease costs for other applicable networks and systems required for PGE operations.	These costs should have been included in the 2015 study as they are necessary for customer service operations.

9080001	825	Bus Continuity & Emergcy Mgmnt (I	Yes	No	Yes	These costs are a result of managing corporate security, records and information, and BCEM operations necessary for customer service operations.	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9080001	915	Corporate Communications	Yes	No	Yes	These costs are the result of managing PGE's mandatory external communications e.g. safety messages, public service announcements, etc.	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9080001	927	Customer Insights	Yes	No	Yes	These costs are a result of supporting and managing data inquiries related to customer data, conducting load research studies, and managing customer program evaluations. These are all tasks necessary for customer service operations.	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9080001	937	Customer Mass Programs	Yes	No	Yes	These costs are the result of managing and promoting mass market programs for customers e.g., paperless billing, payment programs, energy-efficiency programs, etc.	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9080001	999	Corporate Transfers	Yes	No	Yes	These costs represent account entries such as labor loadings, service provider allocations, accruals, amortization of prepaid costs, etc. that are necessary for accurate accounting. These costs are included in the study because they are directly tied to the costs necessary to perform the tasks contained in the functional categories in each customer service account.	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9090001	915	Corporate Communications	Yes	No	Yes	These costs are the result of managing PGE's mandatory external communications e.g. safety messages, public service announcements, etc.	These costs should have been included in the 2015 study as they are necessary for customer service operations.
9090001	999	Corporate Transfers	Yes	No	Yes	These costs represent account entries such as labor loadings, service provider allocations, accruals, amortization of prepaid costs, etc. that are necessary for accurate accounting. These costs are included in the study because they are directly tied to the costs necessary to perform the tasks contained in the functional categories in each customer service account.	These costs should have been included in the 2015 study as they are necessary for customer service operations.

April 15, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 359
Dated April 6, 2015

Request:

For each PGE load forecast group, including the residential forecast groups (i.e. Single-family space heat, Single-family non-space heat, Multi-family space heat, Multi-family non-space heat, Manufactured home space heat, Manufactured home non-space heat, Other residential), the commercial forecast groups (i.e. Food stores, Govt. & education, Health services, Lodging, Misc. Commercial, Merchandise Stores, Office & F.I.R.E., Other Services, Other Trade, Restaurants, Transportation & Communication & Utility) and the Manufacturing groups (i.e. Food Processing, High Tech, Lumber, Metal, Other Manufacturing, Paper, Transportation Equipment):

a. **Please provide the corresponding rate schedule that the forecast group is assigned to in the Company's revenue model.**
b. **Please provide in excel format, with all cell formulae intact, the monthly historical rates charged for each rate schedule referred to in DR 359 part a. from January 1990 to December 2014 in 2005 dollars.**
c. **Please provide in excel format, with all cell formulae intact, the Company's monthly base load forecast for 2016 (in KWh) after the price elasticity and energy efficiency adjustments have been applied.**
d. **Please provide in excel format, with all cell formulae intact, the Company's monthly base load forecast for 2016 (in KWh), before the energy efficiency adjustment or price elasticity adjustment are applied.**
e. **Please provide in excel format, with all cell formulae intact, the Company's monthly base load forecast for 2016 (in KWh), the price elasticity adjustment is applied, but after the energy efficiency adjustment is applied.**[1]

[1] Per e-mail communication with OPUC Staff the part (e) of the response is revised to the following:

f. **Please provide in excel format, with all cell formulae intact, the Company's monthly price elasticity and energy efficiency adjustment adjustments for 2016 (in KWh).**

Response:

PGE objects to this request to the extent it is vague, overly broad and unduly burdensome. Subject to and without waiving its objection, PGE responds as follows:

a) PGE does not directly assign each non-residential forecast group to a rate schedule. Rather, PGE uses a two-step allocation process: first, the forecast group energy is allocated to voltage delivery class using historic voltage delivery shares. These factors are provided in Attachment 359-A. Tab 1 provides the first step allocation factors which are applied to forecast group energy. Tab 2 provides the second set of factors which are applied to voltage delivery class energy to allocate energy to rate schedules. Tab 3 provides the allocations flow chart.

   Note that there are several important details within this process. For the non-residential forecast group energy, the allocation factors are applied only to forecast group energy – the large customers that PGE forecasts individually and all miscellaneous schedules are excluded. An adjustment is also made for the MWh associated with three large customers who are on sub transmission delivery voltage service, but who are not individually forecasted. These adjustments are made to the ECTU[2] and ECOT[3] forecast groups and the monthly MWh amounts are shown as notes to the factors in Tab 1.

   Direct assignment to rate schedules is used for the residential forecast groups, which are allocated entirely to residential voltage delivery service, which in turn is allocated entirely to Rate Schedule 7. Similarly, miscellaneous schedules (15R, 15C, 47, 49, 91, 92 and 95) are mapped directly to their delivery voltage class and to rate schedule (with irrigation energy split to rate schedules 47 and 49).

b) PGE does not keep records of prices for each rate schedule in the manner requested. Literal compliance with this request would require PGE to research every Advice Filing since 1990 and catalog all applicable prices for all rate schedules existing at that time.

   Attachment 359-B contains the prices and price changes with effective dates of the price changes for Rate Schedules 7, 32, 83, 85, 89, and 90 and their predecessor schedules from October 2000 to January 1, 2015 inclusive of applicable supplemental schedules. These rate schedules comprise approximately 99% of the UE 294 projected energy

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Please provide in excel format, with all cell formulae intact, the Company's monthly base load forecast for 2016 (in KWh), before the price elasticity adjustment is applied, but after the energy efficiency adjustment is applied.

[2] ECTU represents Trans, Comm, Util commercial group and includes the following NAICS: 221, 481-493, 513, 562

[3] ECOT represents Other Trade commercial group and includes the following NAICS: 421-444, 446-451, 453-454

consumption for Cost-of-Service customers. The spreadsheet in Attachment 359-B calculates nominal bills for approximate typical usages for each rate schedule corresponding to each schedule's current average profile. These nominal bills include applicable customer charges, demand charges, facilities charges, and volumetric charges.

Because the various prices for each schedule are included in Attachment 359-B, this should allow Staff to isolate certain components for each rate schedule such as volumetric charges with or without supplemental schedules, customer charges, or demand-related charges. Staff may also use the particular inflation adjustment they deem most appropriate to restate the nominal typical bills or components of the nominal typical bills in 2005 dollars.

c) Please find the requested information in Attachment 359-C, tab labeled "DR359_part_c".

d) Please find the requested information in Attachment 359-C, tab labeled "DR359_part_d". As described in PGE response to OPUC Data Request No. 277, an adjustment for a customer co-gen project is shown in this table for the ECTU forecast group.

e) PGE did not perform the requested forecast and does not have the information to respond to this request.

f) Please find the requested information in Attachment 359-C, in two tabs: the tab labeled "DR359_part_f_price" contains the price elasticity adjustment and the tab "DR359_part_f_ee" contains the energy efficiency adjustment.

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Attachment 359-A

Allocation Factors

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UE 294

Attachment 359-B

The Prices and Price Changes

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Attachment 359-C

2016 Base Load Forecasts and Price Elasticity

Provided in Electronic Format only

June 1, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 463
Dated May 18, 2015

Request:

For customers receiving bills by mail:

a. **Describe in detail, and provide dollar value breakdown of the components of the 2014 actual and 2016 budgeted fixed costs associated with sending monthly bills to customers by mail.**

b. **Describe in detail, and provide dollar value breakdown of the components of the 2014 actual and 2016 budgeted marginal costs associated with sending one additional monthly bill to a customer by mail.**

Response:

a. The "2014 Billing Statements" tab of Attachment 463-A provides a breakdown of the components of 2014 actual fixed costs associated with sending monthly bills to customers by mail. Total 2014 costs appear under the "Cost Breakdown" header on page 4. Note that the incremental costs in category III in the Cost Breakdown table are separately itemized and are not included in the totals for Categories I or II. Category II is the sum of Category I incremental costs, plus the fixed costs of production.

   PGE does not create a bottom-up projection of costs for the 2016 budget. For budgeting purposes, we use end of year expenses for 2014, and escalate for factors relevant to the specific budget categories. The RC 727 and 729 budgets are developed in this manner. These budgets have been reduced based on a forecast of the adoption of paperless billing.

b. Categories I and III in the "2014 Billing Statements" tab of Attachment 463-A provide a breakdown of the components of 2014 incremental costs associated with sending monthly bills to customers by mail. Total 2014 costs appear under the "Cost Breakdown" header. PGE does not create a bottom-up projection of these costs for the 2016 budget.

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Attachment 463-A

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Itemized Costs for PGE Billing Statements, Notice Statements, and Credit Letters

PGE Billing Statements

	2014 Volume	$$ / 000	$$ / Piece	Current Yearly Cost
Number of Customer Bills	8,629,476			
Postage			$0.3756	$3,241,459
Presort			$0.0015	$13,247
Number of Sheets (2 up Forms)	4,314,738	$37.79	$0.0189	$163,054
Number of Feet for **duplex** printing	7,910,353			
InfoPrint Click Charge		0.0029	$0.0026	$22,545
InfoPrint Maintenance Bill Production (73.91% of volume)			$0.0051	$43,732
Pitney Bowes APS Maintenance (84.31% of volume)			$0.0092	$79,010
Pitney Bowes File Based Audit Maintenance (84.31% of volume)			$0.0004	$3,765
Trimwinder Maintenance (84.31% of 1st winder)			$0.0003	$2,445
Envelopes (Outer)	8,629,476	$17.64	$0.0176	$152,224
Envelopes (Return)	7,391,032	$15.77	$0.0135	$116,557
Digital Meter Rental			$0.0000	$337
Digital Meter Ink			$0.0003	$2,589
Digital Meter Printing Heads			$0.0001	$725
InfoPrint Ink Cost (B&W Only, Duplex @4% coverage)			$0.0018	$15,706
Labor Cost ** (0% Loading)			$0.0101	$86,731
Total Cost of Production			**$0.4571**	**$3,944,124**

Percentage of InfoPrint usage for Bills	73.91%
APS, One (1) Trimwinder and FBA Percentage	84.31%

PGE Notice Statements

	2014 Volume	$$ / 000	$$ / Piece	Current Yearly Cost
Number of Notices	1,605,887			
Postage			$0.3779	$606,888
Presort			$0.0008	$1,209
Number of Sheets (2 up Forms)	802,944	$37.79	$0.0189	$30,343
Number of Feet for **Duplex** Printing	1,472,063			
InfoPrint Click Charge		0.0029	$0.0026	$4,195
InfoPrint Maintenance Notice Production (13.76% of volume)			$0.0051	$8,138
Pitney Bowes APS Maintenance (15.69% of volume)			$0.0492	$79,010
Pitney Bowes File Based Audit (15.69% of volume)			$0.0004	$701
Trimwinder Maintenance (15.69% of 1st winder)			$0.0003	$455
Envelopes (Outer)	1,605,887	$17.64	$0.0176	$28,328
Envelopes (Return)	1,041,434	$15.77	$0.0102	$16,423
Digital Meter Rental			$0.0000	$63
Digital Meter Ink			$0.0003	$482
Digital Meter Printing Heads			$0.0001	$135
InfoPrint Ink Cost (B&W Only, Duplex @4% coverage)			$0.0018	$2,923
Labor Cost ** (0% Loading)			$0.0105	$16,855
Total Cost of Production			**$0.4958**	**$796,149**

Percentage of InfoPrint usage for Notices	13.76%
APS, One (1) Trimwinder and FBA Percentage	15.69%

PGE Credit Letters

	2014 Volume	$$ / 000	$$ / Piece	Current Yearly Cost
Number of Credit Letters	141,400			
Postage			$0.3970	$56,141
Presort			$0.0186	$2,626
Number of Sheets (2 up Forms)	70,700	$37.74	$0.0189	$2,668
Number of Feet for **Duplex** printing	129,617			
IBM Click Charge		0.0029	$0.0026	$369
InfoPrint Maintenance Letters Production (1.26% of Volume)			$0.0051	$717
InfoPrint Ink Cost (B&W Only, Simplex @4% coverage)			$0.0009	$129
FPS Maintenance (11.12% of volume)			$0.0366	$5,171
Trimwinder Maintenance (11.12% of volume)			$0.0002	$28
Envelopes (Outer)	141,400	$32.58	$0.0326	$4,607
Digital Meter Rental			$0.0003	$39
Digital Meter Ink			$0.0003	$42
Digital Meter Printing Heads			$0.0001	$12
Labor Cost ** (0% Loading)			$0.0596	$8,434
Total Cost of Production			**$0.5727**	**$80,984**

Percentage of InfoPrint usage for Letters	1.21%
FPS, One (1) Trimwinder and FBA Percentage	9.82%

Other PGE Mailings

		$$ / 000	$$ / Piece	Current Yearly Cost
Number of Pieces	1,298,158			

Cost Breakdown

I. RC 727 (PAMS) Incremental Costs (Postage, Clicks, Consumables)

		Annual Volume	Annual Costs	Cost/Piece
Bills		8,629,476	$3,296,270	$0.3820
Notices		1,605,887	$615,832	$0.3835
Letter		141,400	$59,319	$0.4195
	Total	10,376,763	$3,971,421	$0.3827

II. RC 727 (PAMS) Total Cost to Produce (All Inclusive)

		Annual Volume	Annual Costs	Cost/Piece
Bills		8,629,476	$3,512,289	$0.4070
Notices		1,605,887	$721,054	$0.4490
Letter		141,400	$73,709	$0.5213
	Total	10,376,763	$4,307,052	$0.4151

III. RC 729 (Corporate Services Group) Incremental Costs (Forms and Envelopes)

		Annual Volume	Annual Costs	Cost/Piece
Bills		8,629,476	$431,834	$0.0500
Notices		1,605,887	$75,094	$0.0468
Letter		141,400	$7,275	$0.0515
	Total	10,376,763	$514,204	$0.0496

June 5, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 466
Dated May 22, 2015

Request:

With regard to PGE's printing and billing costs embedded in the UE 294/PGE/1300 Macfarlane-Werner Workpaper "2016 TY - Customer Marginal Cost - Work papers.xlsx":

a. **Please provide the postage rates by month for PGE to send bills, notices, credit letters, and all other mail to customers in 2012, 2013, 2014, 2015; and the forecasted rates for 2016;**
b. **Please identify and explain the incentives provided by PGE to encourage paperless billing and electronic delivery of other mailings;**
c. **Please provide the monthly number of pieces of mail sent by PGE to customers each year for years 2005 to 2014; and**
d. **Please provide the number of pieces of mail by month that PGE projects it will send to customers in 2016 and identify the forecasted postage rate expected for each mailing.**

Response:

a. See Attachment 466-A for postage rates by month covering the years 2012 through 2015. PGE does not project the number of pieces of mail for 2016, or the specific postage rate, to determine the 2016 budget. The 2016 budget for Printing and Automated Mail Services (Department 727) is based on PGE's current 2015 postage rate expense escalated for 2016. Then, in order to account for the estimated savings related to paperless billing PGE, reduced this amount by approximately $281,000, an increase of 15% over the 2015 budgeted reduction. PGE's total forecasted postage expense, including the estimated savings from paperless billing, represents a decrease of approximately $744,000 (17%) from 2014 actuals.

b. PGE has not provided any monetary incentives to customers to encourage the Paperless Billing (Paperless) program. Some of the non-monetary incentives PGE has provided include:
   - For an October 2014 sweepstakes promoting the Paperless program, PGE randomly awarded three separate prizes to customers enrolled in the program by the end of the sweepstakes.
   - In March 2014, PGE partnered with Friends of Trees (FOT) on an enrollment promotion that donated $1 to FOT for every new customer that enrolled in the Paperless program during the promotional period. PGE communicated this promotion through several channels, including targeted emails, PGE Update, Home Connection, Facebook, Twitter, FOT (blog posts, newsletters, web), radio, and a web banner on Portlandgeneral.com. PGE also held similar FOT promotions in February of 2012 and March of 2013.

c. See Attachment 466-B.

d. See PGE's response to part (a), above.

UE 294

Attachment 466-A

Provided in Electronic Format only

Postage Rates for 2012-2015

		PAPER CUSTOMER BILLING STATEMENTS						CUSTOMER NOTICES & CREDIT LETTERS				
	Level of Sortation	5-Digit IMB	3-Digit IMB	AADC IMB	Mixed ADC IMB	5-Digit Auto	Full Rate	5-Digit Auto	3-Digit Auto	AADC Auto	Mixed ADC Auto	Full Rate
2012	January*	0.337	0.362	0.365	0.387	0.340	0.465	0.340	0.365	0.368	0.390	
	February	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	
	March	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	
	April	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	
	May	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	
	June	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	
	July	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	
	August	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	0.450
	September	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	0.450
	October	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	0.450
	November	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	0.450
	December	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	0.450
2013	January*	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	
	February	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
	March	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
	April	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
	May	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
	June	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
	July	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
	August	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
	September	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
	October	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
	November	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
	December	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
2014	January*	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
	February	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
	March	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
	April	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
	May	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
	June	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
	July	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
	August	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
	September	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
	October	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
	November	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
	December	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
2015	January	0.378	0.403	0.403	0.432	0.381	0.485	0.381	0.406	0.406	0.435	
	February	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
	March	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
	April	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
	May	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
	June	0.388	0.413	0.413	0.436	0.391		0.391	0.416	0.416	0.439	
	July	0.388	0.413	0.413	0.436	0.391		0.391	0.416	0.416	0.439	
	August	0.388	0.413	0.413	0.436	0.391		0.391	0.416	0.416	0.439	
	September	0.388	0.413	0.413	0.436	0.391		0.391	0.416	0.416	0.439	
	October	0.388	0.413	0.413	0.436	0.391		0.391	0.416	0.416	0.439	
	November	0.388	0.413	0.413	0.436	0.391		0.391	0.416	0.416	0.439	
	December	0.388	0.413	0.413	0.436	0.391		0.391	0.416	0.416	0.439	

2016 Postage rates are not available. The postage budget for 2015 is escalated and used to estimate 2016 budget expense.

*Note: Postage rate increase occurs in month of January.

Postage rate depends on level of sortation. PGE processes addresses through postal sortation software, which allows PGE to receive postage discounts with the USPS.

UE 294

Attachment 466-B

Provided in Electronic Format only

Monthly Pieces of Mail for 2005 through 2014

Year	Category	January	February	March	April	May	June	July	August	September	October	November	December	Total Year
2005	Paper Bills, Notices, and Letters	877,554	897,872	880,892	875,144	866,563	860,777	857,767	865,032	864,513	859,469	867,775	902,525	10,475,883
	Postage	$244,925.85	$250,924.68	$246,411.53	$244,903.98	$242,620.78	$241,015.89	$240,169.18	$240,912.32	$241,916.05	$240,764.35	$254,284.90	$245,986.81	$2,934,836.32
	Other Mailings*	41,302	144,171	156,753	279,416	140,213	190,437	54,374	66,140	105,745	193,442	177,046	102,622	1,651,661
	Postage	$6,814.83	$23,788.22	$25,864.42	$46,103.64	$23,135.15	$31,422.10	$8,971.71	$10,913.10	$17,447.93	$31,917.93	$29,212.59	$16,923.63	$272,515.24
2006	Paper Bills, Notices, and Letters	926,265	946,629	924,452	934,051	910,827	896,074	889,153	901,545	892,290	887,267	872,976	906,130	10,887,659
	Postage	$311,167.67	$279,925.35	$271,449.52	$275,156.61	$268,720.25	$264,234.78	$261,193.58	$266,026.17	$263,290.49	$261,741.82	$257,595.92	$267,053.33	$3,247,555.48
	Other Mailings*	76,198	126,203	96,952	102,993	249,615	126,292	28,997	115,339	63,604	267,750	128,349	84,587	1,466,879
	Postage	$12,572.67	$20,823.49	$15,997.08	$16,993.84	$40,936.86	$20,838.18	$4,784.50	$19,030.94	$10,494.66	$44,178.75	$21,177.85	$13,956.86	$241,785.68
2007	Paper Bills, Notices, and Letters	924,315	949,978	928,143	876,312	901,497	891,534	897,349	910,694	900,460	895,105	883,301	912,677	10,871,365
	Postage	$271,989.93	$276,636.64	$273,551.23	$257,936.21	$277,817.97	$279,910.86	$281,152.45	$286,069.55	$282,585.61	$280,993.38	$277,960.59	$285,763.36	$3,332,367.76
	Other Mailings*	68,137	63,919	208,769	137,545	83,616	131,428	84,053	88,842	253,051	145,130	80,494	120,117	1,465,101
	Postage	$11,242.61	$10,610.55	$34,446.89	$22,694.93	$13,796.64	$21,685.52	$13,868.74	$14,658.93	$41,753.41	$23,946.45	$13,281.51	$19,819.31	$241,805.47
2008	Paper Bills, Notices, and Letters	924,275	960,886	949,038	926,323	925,217	905,372	898,250	906,107	895,306	894,753	869,278	892,098	10,946,903
	Postage	$288,658.63	$301,403.42	$298,594.60	$289,245.36	$298,411.96	$294,551.63	$291,518.29	$294,980.34	$292,259.62	$291,042.14	$284,579.73	$281,230.47	$3,506,476.19
	Other Mailings*	32,995	70,102	244,126	103,354	162,364	140,240	28,611	72,708	219,565	221,424	63,789	174,745	1,534,023
	Postage	$6,203.06	$13,038.97	$45,707.44	$19,399.55	$30,524.43	$26,365.12	$5,693.59	$13,669.10	$41,278.82	$41,627.71	$12,056.12	$32,852.06	$288,415.97
2009	Paper Bills, Notices, and Letters	911,320	962,411	957,487	940,576	933,348	914,986	905,843	919,809	918,326	909,636	892,070	920,941	11,086,753
	Postage	$302,785.69	$314,142.67	$311,442.79	$305,196.01	$311,818.83	$307,743.55	$304,260.94	$308,646.64	$308,642.43	$304,832.71	$298,876.95	$310,641.96	$3,689,031.16
	Other Mailings*	34,960	89,833	80,237	113,561	247,146	102,698	81,252	98,207	213,805	306,451	155,366	157,626	1,681,142
	Postage	$7,533.88	$19,359.01	$17,010.24	$24,097.64	$51,653.51	$21,463.88	$17,022.57	$19,543.19	$42,333.39	$58,838.59	$30,762.47	$31,052.32	$340,670.70
2010	Paper Bills, Notices, and Letters	946,227	962,399	926,532	925,711	920,765	911,880	913,824	916,665	904,052	904,333	881,280	908,399	11,022,067
	Postage	$319,988.28	$323,561.34	$311,567.18	$311,138.59	$309,387.79	$306,284.55	$306,768.97	$307,149.29	$303,309.28	$304,125.78	$296,579.62	$305,011.03	$3,704,871.70
	Other Mailings*	111,143	100,932	190,276	137,867	186,424	146,031	75,653	116,397	196,112	130,097	57,731	74,210	1,522,873
	Postage	$23,984.66	$21,750.85	$40,947.40	$29,710.34	$40,174.37	$31,513.49	$16,310.79	$25,141.75	$42,183.69	$27,944.84	$12,423.71	$15,969.92	$328,055.79
2011	Paper Bills, Notices, and Letters	924,990	956,261	917,807	931,087	913,932	908,480	893,511	895,477	882,209	888,046	864,613	895,743	10,872,156
	Postage	$319,476.23	$321,498.20	$307,369.50	$314,869.64	$311,645.12	$309,685.81	$304,490.69	$305,154.75	$300,824.97	$302,872.00	$293,426.02	$303,491.81	$3,694,804.72
	Other Mailings*	213,451	211,007	134,983	80,616	178,431	95,165	79,454	110,685	168,264	164,831	142,962	101,739	1,681,588
	Postage	$46,169.45	$45,767.42	$29,142.83	$17,453.36	$38,505.41	$20,574.67	$17,225.63	$23,919.03	$36,277.72	$35,570.53	$30,894.88	$21,985.80	$363,486.73
2012	Paper Bills, Notices, and Letters	923,887	929,666	900,017	906,889	892,026	876,976	874,403	870,680	870,247	865,894	851,688	876,271	10,638,644
	Postage	$318,337.31	$323,788.67	$313,431.03	$316,076.60	$310,868.66	$305,526.33	$304,611.73	$303,249.84	$302,568.84	$301,339.08	$296,498.07	$304,770.05	$3,701,066.20
	Other Mailings*	65,505	112,281	174,079	69,355	77,854	38,172	78,992	124,085	70,701	139,011	31,385	119,399	1,100,819
	Postage	$14,280.09	$24,252.70	$38,032.26	$15,119.39	$16,855.39	$8,397.84	$17,101.77	$26,951.26	$15,313.84	$30,304.40	$6,904.70	$25,826.00	$239,339.64
2013	Paper Bills, Notices, and Letters	885,167	903,066	880,829	875,005	855,210	851,890	849,292	863,881	851,727	855,037	840,186	861,119	10,372,409
	Postage	$309,824.38	$323,067.17	$315,162.01	$313,219.60	$306,033.67	$304,830.88	$303,533.84	$308,688.51	$304,349.83	$305,737.07	$300,357.23	$307,416.34	$3,702,220.51
	Other Mailings*	154,557	59,275	99,584	143,757	97,611	113,439	59,843	121,605	112,890	64,909	33,753	100,481	1,161,704
	Postage	$36,939.12	$13,514.70	$23,765.25	$33,920.35	$22,645.75	$26,998.48	$13,285.15	$27,117.92	$26,303.37	$14,344.89	$8,168.23	$24,617.85	$271,621.05
2014	Paper Bills, Notices, and Letters	878,937	885,770	885,939	879,619	856,032	858,692	851,284	873,807	859,556	857,551	834,870	854,706	10,376,763
	Postage	$319,175.95	$334,563.46	$334,766.54	$332,527.00	$323,546.67	$324,713.13	$322,670.78	$329,755.69	$324,335.68	$323,842.29	$315,221.94	$319,369.50	$3,904,488.63
	Other Mailings*	116,946	30,044	43,878	152,181	155,714	125,446	210,524	74,425	77,704	105,034	49,871	121,601	1,263,368
	Postage	$27,950.09	$6,970.21	$10,486.84	$36,675.62	$36,125.65	$29,103.47	$49,052.09	$17,862.36	$18,571.26	$24,788.02	$11,919.17	$29,305.84	$298,810.63

* *Other Mailings - Please note that RC727 does not plan or manage volume of mailings or budget postage associated with. Internal clients are charged back directly for all postage costs incurred.*
Types of Mailings within this category:
Tree Letters (overhead and underground)
Preferred Due Date/Migration/Transfer Letters
Monthly Time of Use Letters
Monthly Renewable Letters
Dunning Letters
Payroll Advice Letters for Retiree and Employees
Misc. Letters and Mailings as the business requires.

Many of these mailings qualify for "standard" postage rates, which are lower than "first-class" rates associated with Bills, Notices and Credit Letters.

CASE: UE 294
WITNESS: ROBERT FONNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 503

Exhibits in Support
Of Opening Testimony

June 15, 2015

STAFF FORECAST OF PROPORTION OF PAPERLESS BILLS IN 2016

PGE SCHEDULES	**7**	**32**	**38**	**47**	**49**	**83**	**85**	**89**	**91 & 95**
	Residential	< 30 kW	< 200 kW	< 30 kW	> 30 kW	31-200 kW	201-4000 kW	> 4 MW	Street lighting
Percent Paperless	20%	16%	16%	4%	3%	18%	27%	28%	3%

CASE: UE 294
WITNESS: ROBERT FONNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 504

Exhibits in Support
Of Opening Testimony

June 15, 2015

STAFF ADJUSTMENT TO CUSTOMER MARGINAL COSTS

		Company		Staff Revised	
Schedule	Description	Annual Billing Expenses	Total Customer Expenses	Annual Billing Expenses	Total Customer Expenses
Schedule 7	Residential	$48.77	$68.81	$48.80	$68.84
Schedule 15	Residential - Area Lights	$50.05	$68.24	$50.05	$68.24
Schedule 15	Commercial - Area Lights	$37.52	$54.45	$37.52	$54.45
Schedule 32	Small Non-Residential (< 30 kW)	$41.18	$70.98	$40.98	$70.77
Schedule 38	Large Non-Residential Time-of-Use	$122.25	$321.81	$122.05	$321.62
Schedule 47	Small Irrigation	$49.18	$77.46	$49.02	$77.29
Schedule 49	Large Irrigation	$49.45	$136.49	$49.28	$136.32
Schedule 83	Large Non-Residential (31-200 kW)	$64.26	$224.02	$64.06	$223.83
Schedule 85	Large Non-Residential (201-1,000 kW)	$144.31	$886.50	$144.10	$886.29
Schedule 89	Large Non-Residential (> 4,000 kW)	$125.33	$5,397.94	$125.17	$5,397.78
Schedule 90	Large Non-Residential (>4,000 kW and Aggregate to >100 aMW)	$22.10	$17,982.84	$22.18	$17,982.92
Schedule 91 & 95	Street and Highway Lighting	$815.35	$948.15	$814.95	$947.76

CASE: UE 294
WITNESS: BRITTANY ANDRUS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

OPENING TESTIMONY

June 15, 2015

Q. Please state your name, occupation, and business address.

A. My name is Brittany Andrus. I am a Senior Utility Analyst with the Public Utility Commission of Oregon. My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97302.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/601.

Q. What is the purpose of your testimony?

A. My testimony addresses two items: 1) Staff's analysis of PGE's calculation of its franchise fee obligations, and 2) Staff's position on the assignment of costs for implementing the portfolio options programs.

Q. What elements of the franchise fee rate did Staff examine in this case?

A. Staff issued seven data requests addressing individual franchise agreements, historical payments by jurisdiction, and the impacts of direct access forecasts on the franchise fee calculation.

Q. Please describe Staff's analysis of PGE's franchise fees.

A. Staff analyzed the Company's filing, reviewed the Company's responses to Staff's data requests and thereby verified the data and calculations used to derive the franchise fee rate. Based on this information, Staff concludes that the franchise fee rate is accurate.

Q. Please describe the portfolio options programs and how they relate to this rate case.

A. Electric companies are required to offer residential and small nonresidential customers a portfolio of rate options, including an option for renewable energy resources and a market-based rate. For PGE, the renewable option is implemented through its Green Source and Clean Wind products, and the market-based rate is a time-of-use product. Participation in the time-of-use product is quite limited, while participation in the renewables programs is significant, surpassing 100,000 residential and small non-residential customers in 2014. Certain costs related to these voluntary programs are to be included in the program rates to ensure that non-participating customers are not paying for them.

Q. What aspects of PGE's portfolio options programs did Staff examine in this case?

A. Staff issued three portfolio options data requests, addressing program expenditures, costs of renewable energy certificates (RECs) acquired, and the cost allocation method employed in estimating costs for PGE program administration. Staff also issued one data request regarding the Company's acquisition of RECs for customers not eligible for portfolio options programs.

Q. Please explain which costs should be included in the rates for the voluntary programs.

A. OAR 860-038-0220(8)(c) requires that "the portfolio rates must include any additional electric company costs that are incurred when a consumer chooses to be served under the portfolio rate option." Section (8)(f) of this rule states that "rates must be established so that costs associated with the development or offering of rate options are assigned to the retail electricity consumers eligible to choose such rate options." Thus, the costs incurred when the programs are chosen by the voluntary program participants are born by those participants, while the costs of developing the product or products to be offered under the portfolio options are allocated to all residential and small commercial customer classes.

Q. How has PGE allocated these costs?

A. PGE's initial response to data request number 370 indicates that $0.40 per MWh sold under the Green Source program is for the indirect program costs incurred, including billing, call center, web development, contract management and others. PGE's supplemental response to this data request, included as Staff Exhibit 602, acknowledges that the basis for the establishment of the $0.40 per MWh is not available. In addition, this amount has not been evaluated since the inception of the portfolio options programs in 2001.[1]

Q. What is Staff's position on this issue?

A. Staff has no information that can be used to determine whether or not the costs incurred when customers choose a portfolio option are paid for by the voluntary customers. Staff concludes that in order to assure that the costs of implementing the voluntary programs are included in the rates those customers pay, PGE should conduct a review of all of the costs incurred in implementing the portfolio options programs. Staff agrees with PGE’s identification of the costs that are appropriately included with program implementation in the DR 370 supplemental response: “…call center and customer service, billing and payment, accounting and budgeting, contracts management (support for

[1] Order No. 01-337 at 3.

RFP processes and standard contract terms), marketing (including web support)." After the costs are known, PGE should calculate the appropriate dollar-per-MWh rate that will compensate for those costs, and include it in the voluntary program rates to ensure that the voluntary participants are paying an amount that covers those costs.

Q. When should this cost review be conducted?

A. PGE should complete the cost analysis and make any necessary changes to its cost allocations for the voluntary programs for 2016 and beyond. PGE should then review this allocation to determine any necessary adjustments on a periodic basis, such as every five years.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 294
WITNESS: BRITTANY ANDRUS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

Witness Qualification Statement

June 15, 2015

WITNESS QUALIFICATION STATEMENT

NAME:	Brittany Andrus
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy, Resources and Planning
ADDRESS:	3930 Fairview Industrial Dr. SE Salem, Oregon, 97302-1166
EDUCATION:	M.B.A. Portland State University, Portland, Oregon B.A. English Michigan State University, East Lansing, Michigan
EXPERIENCE:	I have been employed at the Oregon Public Utility Commission since 2011. My current responsibilities include research, analysis and technical support for electric company proceedings, with an emphasis on resource planning, power costs, and qualifying facilities under PURPA. I was previously employed for 17 years by the Bonneville Power Administration, a wholesale power marketing agency within the federal Department of Energy. My duties included energy efficiency planning and program management, long term load and revenue forecasting, long term power sales contracts, rate impact analysis, short term load forecasting, power and transmission scheduling, and management of load forecasting data and processes.

CASE: UE 294
WITNESS: BRITTANY ANDRUS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 602

Exhibits in Support
Of Opening Testimony

June 15, 2015

May 5, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE First Supplemental Response to OPUC Data Request No. 370
April 30, 2015

Request:

Please provide an explanation of PGE's method for allocating costs to the voluntary renewables programs, including but not limited to program management, contracts management, billing, call center, product development, marketing (including web development), and regulatory affairs. Please include in this explanation a description of PGE's method for monitoring the accuracy of this allocation method, any changes to the allocation method during calendar years 2011 through 2014, and a description of the impetus for those changes.

Response (Dated April 27, 2015):

Fixed Renewable/Clean Wind Option
PGE's current renewable portfolio options include Fixed Renewable Option, Renewable Usage Option, and Habitat Option. Customers enrolling in the Fixed Renewable Option (also called Clean Wind) currently pay $2.50 per month for 200 kWh of renewable energy credits (RECs) and to make a contribution to a renewable resources development and demonstration fund. Of the $2.50 per 200 kWh block purchased, $1.50 is deposited into the development fund and $1.00 goes to the purchase of RECs on that customer's behalf. Table 1, below, lists the current allocation (effective January 1, 2013) plus the previous allocation.

Table 1: Clean Wind			
Effective December 1, 2008			
RECs	$ 2.00	per month	57%
Clean Wind Development Fund	$ 1.50	per month	43%
Total premium to customers	$ 3.50	per month	100%
Effective January 1, 2013			
RECs	$ 1.00	per month	40%
Clean Wind Development Fund	$ 1.50	per month	60%
Total premium to customers	$ 2.50	per month	100%

Renewable Usage/Green Source Option
Customers enrolling in the Renewable Usage Option (also called Green Source), pay a variable renewable power premium based on their monthly usage. The premium currently pays for RECs and administrative fees, according to the Tariff (Schedules 7 and 32). Only the Green Source customers contribute to administrative costs of the portfolio options program. Effective January 1, 2013, PGE reduced the price of the Clean Wind and Green Source options based on lower current and projected REC prices.

Table 2: Green Source			
Effective January 1, 2009 - 2012			
PGE administration	$ 0.40	per MWh	3%
Program marketing and administration	$ 3.10	per MWh	26%
RECs	$ 6.00	per MWh	50%
Green Source Reserve Fund	$ 2.50	per MWh	21%
Total premium to customers	$ 12.00	per MWh	100%
Effective January 1, 2013			
PGE administration	$ 0.40	per MWh	5%
Program marketing and administration	$ 4.10	per MWh	51%
RECs	$ 3.50	per MWh	44%
Green Source Reserve Fund	$ -	per MWh	0%
Total premium to customers	$ 8.00	per MWh	100%

Five percent of the Green Source customer payment is for PGE indirect services provided to the renewable power program (e.g., contracts management, finance and accounting, billing, call center support, marketing including web development, and regulatory affairs). The five percent is applied to PGE's Other Revenues, which is an offset to PGE's revenue requirement in a test year forecast. The 51% of the customer payment covers program marketing and administration (i.e., Green Mountain Energy contract) in addition to the costs of services provided by the PGE renewables program management.

Habitat Option

Customers enrolling in the Habitat option pay $2.50 per month, 100% of which is distributed to a nonprofit agency for habitat restoration. The agency receiving the customer contributions for habitat is currently the Nature Conservancy.

PGE has not performed analyses to compare allocations to actual costs. Given that PGE has proposed a new portfolio option, Renewable Future Solar, PGE will be reviewing the allocation of costs for all the portfolio options.

Supplemental Response (Dated May 05, 2015)

In a telephone conversation with Staff April 30, 2015, Staff requested that PGE supplement this request and provide more information regarding: 1) the process by which PGE determined what back office support is provided to the renewables program and thus, a share of those costs paid by renewables customers; 2) how PGE determined that $0.40 per MWh (5%) was an appropriate amount; and 3) whether PGE has evaluated the $0.40 per MWh (5%) allocation amount to determine how it compares to the costs of back office services provided to the program.

1) After approval of the Green Source renewable option, PGE estimated administrative costs and support for the program, other than direct program management from the renewables program manager, to be about 5% and then determined the portion of the customer's payment (now $0.40 per MWh). PGE has not found records or other documentation of this decision; rather it rests in the institutional memory of employees. At the time the amount was set, PGE intended to cover customer service, billing and shared services like legal and regulatory that was specific to the program.

   With regard to the PGE back office support provided to the program, PGE identifies the following as providing support specific to the renewables programs: call center and customer service, billing and payment, accounting and budgeting, contracts management (support for RFP processes and standard contract terms), marketing (including web support). With regard to product development and general regulatory support, PGE views these as functions supported by all eligible customers.

2) See above. Due to PGE staff turnover and retirements, we have found no documentation that supports how the 5% was determined to be the appropriate amount.

3) PGE has not evaluated the $0.40 or 5% allocation amount to determine how it compares with the actual or approximate costs of the support services provided to the program. Moving forward, PGE will evaluate the 5% allocation to determine if the percentage is adequate to cover the back office support provided to the program.

CASE: UE 294
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

OPENING TESTIMONY

June 15, 2015

Q. Please state your name and business address.

A. My name is Marianne Gardner. My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97302.

Q. Please describe your educational background and work experience.

A. I am a Senior Revenue Requirement Analyst employed in the Energy Rates, Finance, and Audit Division of the Public Utility Commission of Oregon (OPUC). My Witness Qualification Statement is found in Exhibit Staff/701.

Q. What is the purpose of your testimony?

A. I am the revenue requirements summary witness for the Public Utility Commission of Oregon Staff (Staff) in this proceeding. As such, I explain my adjustments and summarize the other Staff-sponsored adjustments and issues regarding Portland General Electric's (PGE's or Company's) filing in this docket, identified as UE 294, that remains contested. In addition, I provide some detail regarding the partial settlement reached in principal in the docket.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/702, consisting of 1 page.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Part I – Revenue Requirement
Part II – Contested Issues

Part I – Revenue Requirement

Q. Please provide a list of the rate case topics that Staff reviewed, identify the Staff analyst who reviewed the topic, and the status of the topic.

A. Listed in Table A is the requested information.

Table A

Staff	Settled	Contested	No Adjustment Required
Andrus B.		Portfolio Options Program	
Breish	Energy Efficiency		
Bahr	Medical Benefits, Pensions		Affiliated Interest Charges, Taxes Other Than Income
Bhattacharya		Marginal Generation Costs & Load Forecast	
Boyle	Fee Free Bankcard		
Compton	R&D	LRIC, Rate Spread and Rate Design	
Fonner		Marginal Customer Cost, Postage, and Load Forecast	
Gardner	Revenue Sensitive Rates, Uncollectible Expense, Escalation, Workforce Levels, Wages and Salaries, Incentives & Bonuses	Revenue Requirement, Interest Synchronization	Amortization Expense, Income Taxes, Accumulated Deferred Income Taxes, Working Capital, Miscellaneous Labor, Budgeting Process
Johnson	Construction Overheads, Sponsorships, Memberships, Dues and Donations	Trojan Refund - Schedule 143	Generation Expenses, Transmission and Distribution O&M Expense, Fuel Stock, Material and Supplies, Miscellaneous Deferred Debits, IT Projects, Environmental Remediation
Moore	Advertising		Marketing, Promotional Activities, Concessions, PCB Transformer Testing Project
Muldoon		Cost of Capital	
Ordonez	Carty Generation Station, Grassland Switchyard, Clackamas Surface Collector Project		Other Electric Plant Acquisitions
Wittekind	Various A&G and D&O		Existing Plant, Miscellaneous Rate Base, Rate Base Reductions

Q. Please describe Table A.

A. Table A describes three categories of issues. The first category is for settled topics, and Staff will present separate testimony on those topics in support of the partial stipulation in July. The second category is for contested issues, and Staff is presenting individual testimony on those issues in its opening testimony. The third category is for those topics that Staff investigated and concluded no adjustment was necessary. For all three categories, Staff reviewed the Company's filing, including the standard data request responses, initiated an additional 347 data requests, and reviewed responses to parties data requests.

Q. Is there any other rate case topic that is not listed in Table A?

A. Yes. Power Costs are included in PGE's requested base revenue requirement. However, this issue has a separate schedule within Docket UE 294 for which John Crider is the responsible Staff analyst.

Q. Is there a difference between the revenue requirement for base rates requested by PGE and the amount Staff proposed?

A. Yes. To summarize, PGE requested an increase in revenue requirement related to base rates of approximately $38.75 million. This $38.75 million revenue requirement amount does not include PGE's requested revenue requirement for the Carty project. For purposes of settlement, Staff proposed 15 adjustments to PGE's requested revenue requirement, 14 of which change revenue requirement. Additionally, Staff identified several other issues with PGE's filing. A partial settlement has been reached on some of Staff's proposed adjustments. However, a proposed revenue requirement amount is unavailable at this time.

Q. Which parties have agreed to the partial settlement?

A. PGE, Citizens Utility Board of Oregon (CUB), Industrial Customers of Northwest Utilities (ICNU), Kroger Co. (Kroger), and Staff have agreed to the settlement in principal. There may be other parties to the settlement as well.

Q. Has a formal settlement agreement been filed with the OPUC?

A. Not yet. However, the parties are currently drafting an agreement and will be drafting supporting testimony as well.

Q. Please list Staff's settled issues to the Company's filed general rate case, and the associated adjustments.

A. I have prepared the following two lists. Table B contains issues S-4, S-6, S-8, S-11, and S-15, which stipulating parties settled collectively for ratemaking purposes. For these issues, stipulating parties agreed that test year expense will be reduced by a total of $8 million, and rate base will be reduced by $9 million. Other terms will be fully explained in the partial settlement. Staff's allocation of these amounts in Table B represents Staff's perspective on the issues for illustrative purposes only, and does not necessarily reflect the positions or views of the other parties to the partial settlement regarding allocation of the agreed-upon reductions. I base this assignment on the Commission's past practices and policies as applied in previous rate cases and as applied by Staff in the current rate case.

Listed in Table C are the remaining settled issues, S-1, S-5, S-7, S-9, S-12, S-13, and S-14, for which stipulating parties agreed to as well. Staff assigned to these issues will explain each issue more fully in their respective testimonies supporting the partial settlement.

Table B

Item	Staff	Description	Settled Collectively Adjustments ($000)		
			Revenue	Expense	Rate Base
S-4	Gardner	Wages & Salaries		($4,326)	($1,824)
S-6	Wittekind	Various A&G		($1,195)	
S-8	Bahr	Pensions		($1,300)	($7,176)
S-11	Gardner	Escalation		($778)	
S-15	Boyle	Fee Free Bankcard		($401)	
		TOTAL		($8,000)	($9,000)

Table C

Item	Staff	Description	Settled Individually Adjustments ($000)		
			Revenue	**Expense**	**Rate Base**
S-1	Gardner	Uncollectibles (rate = 0.4032%)		$0	
S-5	Moore	Advertising		($70)	
S-7	Bahr	Medical Benefits		($992)	
S-9	Johnson	Dues and Donations		($194)	
S-12	Breish	Energy Efficiency		($237)	
S-13	Compton	R&D		($1,100)	
		TOTAL		($2,593)	

Q. Will Staff provide testimony on the above settled items?

A. Yes. I and other Staff will submit separate testimony in support of the settled items in July.

Q. Are there any other matters in PGE's UE 294 initial filing not resolved through the above-described settled items that will impact 2016 revenues?

A. Yes. There are three additional subjects presented in the filing that impact revenues. The first is Power Costs. Power Costs are included in PGE's requested base revenue requirement. However, this issue has a separate schedule within Docket UE 294. Parties have filed the first round of testimony. Staff witness John Crider filed opening testimony and Staff exhibits 100-105 on May 28, 2015. The next step in the Power Cost schedule is PGE's filing of reply testimony.

The second matter is regarding capital or rate base additions. Parties have settled certain terms regarding capital additions, Clackamas Surface Collector Project, Grassland Switchyard, and Carty. Parties have agreed to remove the Grassland Switchyard capital costs from the Company's base business case, and include these costs with Carty's gross plant. The Clackamas Surface Collector Project will be included in the Company's rate base pending a PGE officer attestation when Clackamas Surface Collector Project is placed in service prior to January 1, 2016. Staff witness Ordonez will further explain in his opening testimony, Exhibit 900.

Lastly, PGE has reduced their base revenue requirement request by $56.2 million. Staff issued Data Request No. 181 and requested from the Company further explanation of this reduction described as "Changes in Supplemental

Schedules" at the top of page 3 of PGE's Executive Summary.[1] The Company's response entitled "Estimated Changes in Supplemental Schedules:2016" is appended as Staff Exhibit 702. The revenue from these supplemental schedules is independent of the base revenue requirement request and base rates.

Q. Does Staff agree with PGE's proposed changes as shown in Exhibit 702?

A. No. Staff questions PGE's proposal concerning the Trojan nuclear fuel credit contained in Schedule 143, Spent Fuel Adjustment. Staff witness Judy Johnson offers testimony regarding this subject in Exhibit 800.

Q. Does this conclude your testimony on the partial settlement?

A. Yes.

Part II – Contested Issues

Q. Please provide a listing of the responsible Staff witnesses for each contested issue and the associated exhibit number.

A. The table below provides the requested list.

Table D

Item	Staff Witness	Description	Status	Exhibit No.
S-0	Matt Muldoon	Cost of Capital	Contested	200
S-3	Marianne Gardner	Interest Synchronization	Contested	700
S-10	Jorge Ordonez	Capital Additions	Partial Settlement	900

[1] The Executive Summary is included with PGE's initial filing of UE 294 Request for a General Rate Revision, February 12, 2015.

I-1	George Compton	LRIC, Rate Spread and Rate Design	Contested	300
I-4	Suparna Bhattacharya	Marginal Generation Costs & Load Forecast	Contested	400
I-5	Robert Fonner	Load Forecast	Contested	500
I-6	Robert Fonner	Marginal Customer Costs & Postage	Contested	500
I-8	Brittany Andrus	Portfolio Options Program	Contested	600
Sch. 143	Judy Johnson	Nuclear Fuel Credit	Contested	800

Q. Will each Staff witness provide testimony on each of the above items?

A. Yes. Each Staff witness identified in Table D will provide individual testimony on each contested item for which they are responsible that will clarify Staff's position.

Q. Has Staff provided estimated adjustments to the 2015 test revenues, expenses, or rate base dollars for any of these contested issues?

A. Yes. Staff provides the following estimates. The proposed adjusted amounts for the remaining contested items are still pending a final determination. Staff witnesses will explain the amounts more fully in each of their respective testimonies.

Table E

Item	**Staff Witness**	**Description**	**Status**	**Proposed Adjustment ($000)**		
				Revenue	Expense	Rate Base
S-0	Muldoon	Cost of Capital	(Contested)	($32,074)		
S-3	Gardner	Interest Synchronization	(Contested)	$2,694		
I-6	Fonner	Marginal Customer Cost/Postage	(Contested)			
Sch. 143	Johnson	Nuclear Fuel Credit	(Contested)	($17,344)		

Q. Briefly describe the contested adjustment for Item S-3, Interest Synchronization, for which you are responsible.

A. According to long-standing Commission policy, for ratemaking purposes, Staff routinely synchronizes interest expense to reflect changes to the regulated utility's cost of capital as initially filed in a general rate case. This is consistent with the treatment in PGE's last general rate case, UE 283. The Item S-3 adjustment depends on Staff witness Matt Muldoon's proposed adjustment S-0, Cost of Capital. Mr. Muldoon has recommended in S-0 an adjustment to the Company's filed cost of capital, of which the weighted cost of debt is a component. Because interest expense on long-term debt is tax deductible, Mr. Muldoon's proposed weighted cost of debt impacts income tax expense for ratemaking purposes. Once parties agree on the weighted cost of debt, interest must be coordinated or synchronized to determine the related adjustment for the income tax calculation.

The amount is calculated on the base year as follows:

+ Net Rate Base

X Staff's Recommended (or Authorized) Weighted Cost of Debt

= Allowable Interest Deduction

- Company's Reported Interest Deduction

= Interest Coordination Adjustment

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 294
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Witness Qualification Statement

June 15, 2015

WITNESS QUALIFICATION STATEMENT

NAME:	Marianne Gardner
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Revenue Requirement Analyst Rates, Finance & Audit
ADDRESS:	3930 Fairview Industrial Dr SE, Oregon 97308-1088
EDUCATION:	Master of Business Administration Oregon State University, Corvallis, Oregon Bachelor of Science in Accounting Montana State University, Bozeman, Montana CPA, Oregon

EXPERIENCE:

I have been employed by the Public Utility Commission of Oregon since March 2013, with my current position being a Senior Revenue Requirement Analyst, in the Energy - Rates, Finance and Audit Division. My responsibilities include research, analysis, and recommendations on a range of cost, revenue and policy issues for electric and natural gas utilities. As the revenue requirement summary witness, I have provided testimony in dockets UE 263, UG 246, UE 283, and UG 284.

I have approximately 20 years of professional accounting experience, including:

- Thirteen years as a cost accountant with responsibilities including cost accounting, budgeting, product costing, and the preparation of management reports;
- Four years experience in public accounting working in the areas of audit, tax and financial accounting for individual and small business clientele; and,
- Three years experience in non-profit accounting for an agency administrating funds under the Federal Job Training Partnership Act.

CASE: UE 294
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 702

Exhibits in Support
Of Opening Testimony

June 15, 2015

Estimated Changes in Supplemental Schedules: 2016*

Schedule	Annual change	Comments
Schedule 102 Regional Power Act Exchange Credit	($14,679,957)	Updated every other year for BPA's Average System Cost process
Schedule 105 Regulatory Adjustments	$6,714,409	Updated annually
Schedule 123 Decoupling Adjustment	($10,972,035)	Updated annually
Schedule 143 Spent Fuel Adjustment	($11,043,570)	DOE refund should be fully amortized at end of 2016 and price set to zero January 1, 2017
Schedule 144 Capital Projects Adjustment	($26,233,022)	Should be fully amortized at end of 2015 and price set to zero January 1, 2016
Total Estimated Change in Supplementals	($56,214,175)	

* For more information, see PGE Exhibit 1400, Section IV. Pricing, Other Rate Schedule Changes

CASE: UE 294
WITNESS: JUDY JOHNSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

OPENING TESTIMONY

June 15, 2015

Q. Please state your name, occupation, and business address.

A. My name is Judy Johnson. I am a Senior Economist at the Public Utility Commission of Oregon. My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97302.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/801.

Q. What is the purpose of your testimony?

A. I will provide testimony opposing Portland General Electric's (PGE) proposal for Schedule 143, Spent Fuel Adjustment.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/802, consisting of 1 page.

Q. What issues did you cover in this Docket?

A. I analyzed Issues S-9 Dues and Donations, I-2 Construction Overheads, I-7 Coal Inventory, and Schedule 143, Spent Fuel Adjustment.

Q. What was the outcome of the other three issues that are not covered in this testimony?

A. Issues S-9, I-2, and I-7 are part of a partial stipulation that will be filed in the docket or have otherwise been resolved..

Q. Did you write data requests for additional information about the three issues not covered in this testimony?

A. Yes. Issue S-9, Dues and Donations, had six data requests that were sent to PGE. Issue I-2, Construction Overheads, had 10 data requests that were sent to PGE. Issue I-7, Coal Inventory, had 14 data requests that were sent to PGE. PGE answered all data requests.

Q. Will you be discussing these three issues that have been settled in other testimony?

A. Yes. Staff will be preparing testimony in support of the partial stipulation reached in this docket. I will prepare testimony supporting the settlement reached on the three issues discussed previously. The fourth issue, Schedule 143, Spent Fuel Adjustment is a contested adjustment and I will discuss that issue in this testimony.

Q. Please explain what Schedule 143, Spent Fuel Adjustment represents.

A. In Docket UE 283, PGE offered to amortize over three years the refund from the Department of Energy (DOE) pertaining to the Trojan Nuclear Decommissioning Trust.

Q. Is PGE proposing something different in the current Docket UE 294?

A. Yes. PGE is now proposing to change the amortization from three years to two years.

Q. Doesn't this change help protect customers from increased rates on January 1, 2016?

A. Yes. However, on January 1, 2017, the refund will have been completely amortized back to customers and these same customers will see an automatic rate increase in rates due solely to the refund's completion.

Q. What is Staff proposing?

A. Staff is proposing to leave the amortization at three years. This will mean a smaller rate decrease now and a smaller rate increase when the amortization is complete. Customers will not see the increase in their bills until January 1, 2018.

Q. Please explain how Exhibit 802 ties into Staff's recommendation?

A. Exhibit 802 is PGE's response to Staff data request number 262. This Exhibit shows how PGE's proposal would work. The first chart shows how the account is being amortized in 2015. The chart shows that PGE expects to credit customers $17.3 million in 2015. The second chart shows PGE's proposed credit for 2016 of $34.0 million.

Q. How does Staff's proposal change that?

A. Staff proposal is to credit customers an equal amount spread over three years. Staff proposes to credit customers $17.0 million in 2015, 2016, and 2017. On January 1, 2018, when the account is zero, customer's rates will increase by $17.0 million because the credit is finished. Under PGE's proposal the account is zeroed out at the end of 2016 and on January 1, 2017, customer's rates will increase by $34.0 million because the credit is finished.

Q. Is it true that under either proposal customer's rates will automatically increase?

A. Yes. However, under PGE's proposal the increase is $34.0 million on January 1, 2017, and under Staff's proposal the increase would only be $17.0 million and that would not happen until January 1, 2018.

Q. Overall, why does Staff believe its proposal should be preferred?

A. Staff believes its proposal results in less of a rate shock to customers.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 294
WITNESS: JUDY JOHNSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Witness Qualifications Statement

June 15, 2015

WITNESS QUALIFICATION STATEMENT

NAME:	JUDY A. JOHNSON
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	SENIOR ECONOMIST IN ENERGY, RATES, FINANCE, AND AUDIT
ADDRESS:	3930 FAIRVIEW INDUSTRIAL DR. SE, SALEM, OREGON 97308-1088
EDUCATION:	MBA with an emphasis in Statistics from Eastern Washington University Cheney, Washington BA in Accounting from Eastern Washington University Cheney, Washington

EXPERIENCE:

3/95-Present	I have been employed by the Public Utility Commission of Oregon since March of 1995. My current position being a Senior Economist in the Utility Program's Energy - Rates, Finance, and Audit Division.
6/77-2/95	I was employed by Avista Corporation, an electric and natural gas utility located in Spokane, Washington. The majority of my employment was spent in the Rates and Regulatory Affairs Department as a Senior Rate Analyst. I have prepared testimony and exhibits in numerous electric and natural gas rate cases, primarily in the area of results of operations and revenue requirement.

CASE: UE 294
WITNESS: JUDY JOHNSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 802

Exhibits in Support
Of Opening Testimony

June 15, 2015

Calculation of Revenues at Current Prices

Schedules	Sch 143 MWh	Current Prices Part A mills/kWh	Current Prices Part B mills/kWh	Current Revenues Part A Revenues	Current Revenues Part B Revenues	Revenues at Current Prices
Schedule 7	7,620,805	(0.96)	(0.31)	($7,315,973)	($2,362,450)	($9,678,423)
Schedule 15	16,308	(0.76)	(0.25)	($12,394)	($4,077)	($16,471)
Schedule 32	1,599,950	(0.89)	(0.29)	($1,423,956)	($463,986)	($1,887,941)
Schedule 38	39,036	(0.90)	(0.29)	($35,132)	($11,320)	($46,453)
Schedule 47	20,845	(1.09)	(0.35)	($22,721)	($7,296)	($30,017)
Schedule 49	62,677	(1.05)	(0.34)	($65,811)	($21,310)	($87,122)
Schedule 83-S	2,795,179	(0.89)	(0.29)	($2,487,710)	($810,602)	($3,298,312)
Schedule 85-S	2,464,564	(0.86)	(0.28)	($2,119,525)	($690,078)	($2,809,603)
Schedule 85-P	713,162	(0.84)	(0.27)	($599,056)	($192,554)	($791,610)
Schedule 89-S	0	(0.82)	(0.27)	$0	$0	$0
Schedule 89-P	851,370	(0.80)	(0.26)	($681,096)	($221,356)	($902,452)
Schedule 89-T	63,435	(0.79)	(0.25)	($50,114)	($15,859)	($65,972)
Schedule 75-T	19,637	(0.79)	(0.25)	($15,513)	($4,909)	($20,423)
Schedule 90-P	1,498,007	(0.78)	(0.25)	($1,168,446)	($374,502)	($1,542,948)
Schedule 91/95	74,544	(0.76)	(0.25)	($56,654)	($18,636)	($75,290)
Schedule 92	3,243	(0.80)	(0.26)	($2,594)	($843)	($3,437)
Schedule 485-S	438,339	(0.86)	(0.28)	($376,971)	($122,735)	($499,706)
Schedule 485-P	273,576	(0.84)	(0.27)	($229,804)	($73,866)	($303,670)
Schedule 489-S	14,393	(0.82)	(0.27)	($11,802)	($3,886)	($15,688)
Schedule 489-P	533,149	(0.80)	(0.26)	($426,519)	($138,619)	($565,138)
Schedule 489-T	305,980	(0.79)	(0.25)	($241,724)	($76,495)	($318,219)
Totals	19,408,200			($17,343,516)	($5,615,378)	($22,958,893)

Calculation of Revenues at Proposed Prices

Schedules	Sch 143 MWh	Proposed Prices Part A mills/kWh	Proposed Prices Part B mills/kWh	Proposed Revenues Part A Revenues	Proposed Revenues Part B Revenues	Revenues at Proposed Prices
Schedule 7	7,620,805	(1.88)	0.00	($14,327,114)	$0	($14,327,114)
Schedule 15	16,308	(1.52)	0.00	($24,788)	$0	($24,788)
Schedule 32	1,599,950	(1.76)	0.00	($2,815,913)	$0	($2,815,913)
Schedule 38	39,036	(1.90)	0.00	($74,168)	$0	($74,168)
Schedule 47	20,845	(1.76)	0.00	($36,687)	$0	($36,687)
Schedule 49	62,677	(1.90)	0.00	($119,087)	$0	($119,087)
Schedule 83-S	2,795,179	(1.72)	0.00	($4,807,709)	$0	($4,807,709)
Schedule 85-S	2,464,564	(1.69)	0.00	($4,165,114)	$0	($4,165,114)
Schedule 85-P	713,162	(1.65)	0.00	($1,176,717)	$0	($1,176,717)
Schedule 89-S	0	(1.66)	0.00	$0	$0	$0
Schedule 89-P	851,370	(1.61)	0.00	($1,370,705)	$0	($1,370,705)
Schedule 89-T	63,435	(1.58)	0.00	($100,227)	$0	($100,227)
Schedule 75-T	19,637	(1.58)	0.00	($31,027)	$0	($31,027)
Schedule 90-P	1,498,007	(1.52)	0.00	($2,276,971)	$0	($2,276,971)
Schedule 91/95	74,544	(1.52)	0.00	($113,308)	$0	($113,308)
Schedule 92	3,243	(1.55)	0.00	($5,026)	$0	($5,026)
Schedule 485-S	438,339	(1.69)	0.00	($740,792)	$0	($740,792)
Schedule 485-P	273,576	(1.65)	0.00	($451,401)	$0	($451,401)
Schedule 489-S	14,393	(1.66)	0.00	($23,892)	$0	($23,892)
Schedule 489-P	533,149	(1.61)	0.00	($858,370)	$0	($858,370)
Schedule 489-T	305,980	(1.58)	0.00	($483,448)	$0	($483,448)
Totals	19,408,200			($34,002,464)	$0	($34,002,464)

CASE: UE 294
WITNESS: JORGE ORDONEZ

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Opening Testimony

June 15, 2015

Q. Please state your name, occupation, and business address.

A. My name is Jorge Ordonez. I am employed by the Public Utility Commission of Oregon (OPUC) as a Senior Financial Economist in the Energy Resources and Planning Division. My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97302-1166.

Q. Please describe your educational background and work experience.

A. My Witness Qualifications Statement is found in Exhibit Staff/901, Ordonez /1.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is twofold: first, to review Portland General Electric's (PGE's or Company's) request that the OPUC include in rates the costs of the Carty Generation Station (Carty) when placed in service, and second, to review the Company's capital additions intended to be put into the rate base before rates enter into effect on January 1, 2016.

In conducting the aforementioned review, Staff referred to the Company's initial filing and approximately 40 initial and follow-up data requests (DRs).

Q. Have you prepared an exhibit for this docket?

A. Yes, I have prepared Exhibit Staff/901; Witness Qualification Statement.

SUMMARY RECOMMENDATION

Q. What are your summary findings and recommendations?

A. Regarding the inclusion in rates of the costs of Carty when placed in service, Staff and Parties have reached a stipulation regarding this topic, agreeing that PGE's decision to construct Carty was prudent and recommending that the Commission approve the Carty tariff rider requested by PGE to reflect the prudently-incurred costs and benefits of the plant when it begins providing service to customers, with multiple conditions.

Regarding PGE's capital additions, Staff and Parties have reached a stipulation regarding two major capital additions raised by Staff in settlement negotiations: the Grassland Switchyard and the Clackamas PME – Surface Collector C project (Clackamas Surface Collector Project). As for the Grassland Switchyard, the net rate base of this project of $24.686 million will be removed from the year-end 2015 rate base until Carty is in service. As for the Clackamas Surface Collector Project, when this project is placed in service, PGE will file an attestation from an officer that the plant has been placed in service.

Staff will provide testimony supporting the aforementioned stipulated issues at a later date.

Q. What other matter, if any, would you like to address?

A. Staff anticipates that other parties may file testimony regarding PGE's request, particularly regarding capital additions to rate base. Staff reserves the right to address this in its next round of testimony.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 294
WITNESS: JORGE ORDONEZ

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 901

Witness Qualification Statement

June 15, 2014

WITNESS QUALIFICATION STATEMENT

NAME	Jorge D. Ordonez
EMPLOYER	Public Utility Commission of Oregon
TITLE	Senior Financial Economist, Energy Resources and Planning Division
ADDRESS	3930 Fairview Industrial Dr SE, Salem, Oregon 97302-1166
EDUCATION AND TRAINING	Utility Management Certificate Willamette University, Oregon, 2008
	Certificate in Management of Hydropower Development Swedish International Development Cooperation Agency, Sweden, 2006 & South Africa, 2007
	Fulbright Scholar, MBA, concentration in finance Willamette University, Oregon, 2005
	Certificate in Project Appraisal and Management Maastricht School of Management, Netherlands, 2002
	BS, Mechanical Engineering, thermal power efficiency Electrical & Mechanical Engineering School San Antonio Abad University, Peru, 1998
EXPERIENCE	I received a Bachelors of Science degree in Mechanical Engineering from San Antonio Abad University in Cusco, Peru in 1998. Subsequently, as a Fulbright Scholar, I received an MBA with an emphasis in finance from Willamette University in 2005. From 1999 to 2008, I worked for a Peruvian power generation company and was promoted many times, working as an Engineer, Resource Scheduler, Manager of Economic Planning and Vice-President of Generation, Commercial and Trading. Since January 2009, I have been employed by the Public Utility Commission of Oregon as a Senior Financial Economist, evaluating utilities' issuance of securities, cost of capital, mergers and acquisitions, property sales, cost of service studies, marginal cost studies, rate spread and rate design, integrated resource plans, purchased gas costs, and power costs.

CERTIFICATE OF SERVICE

UE 294

I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 15th day of June, 2015, at Salem, Oregon.

Kay Barnes

Kay Barnes
Public Utility Commission
3930 Fairview Industrial Drive SE
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UE 294 – SERVICE LIST

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