Oregon
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August 22, 2023

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION ATTENTION: FILING CENTER
PO BOX: 1088
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RE: Docket No. UE 416 – In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision.

Attached for filing are the following Staff Rebuttal Testimony:

Exh 2900_2909 CONF, Muldoon
Exh 3000 CONF, Chipanera
Exh 3100_3101 CONF, Scala
Exh 3200, Stevens_Young
Exh 3300_3302 CONF, Stevens
Exh 3400, Dlouhy
Exh 3500, Farrell
Exh 3600, Jent
Exh 3700, Dlouhy_Muldoon_Scala_Stevens
Exh 3800, Dlouhy_Jent_Pileggi
Exh 3900, Nottingham_Shearer
Exh 4000, Ankum
Exh 4100_4101 CONF, Bolton_Stevens
Exh 4200, Shierman

Cover letter, Certificate of Service and Service List are also included here.

/s/ Kay Barnes
Oregon Public Utility Commission
(971) 375-5079
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CERTIFICATE OF SERVICE

UE 416

I certify that this day I served the foregoing document upon all the following parties or attorneys of 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 (which may include a link to a secure shared file service).

Dated this 22nd day of August, 2023 at Salem, Oregon

Kay Barnes

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CASE: UE 416
WITNESS: Matt Muldoon

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 2900

REDACTED
REBUTTAL TESTIMONY
Overview, Public Comments, Overall Rate of Return, and Return on Equity
(Subject to Protective Order No. 23-039)

You Must Have Signed Appendix B of the Protective Order to Receive the Confidential Version of this Exhibit.

August 22, 2023

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

A. My name is Matt Muldoon. I am employed as Manager, Accounting and Finance Section within the Rates, Safety, and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is found in Exhibit No. Staff/400 and my witness qualification is provided in Exhibit No. Staff/401.

Q. What is the purpose of your testimony?

A. I introduce Staff-sponsored adjustments and rebuttal positions regarding the Portland General Electric Company (PGE or Company) request for a general rate revision, docketed as Docket No. UE 416. Please refer to Exhibit No. Staff/3000, the testimony of Itayi Chipanera, for additional detail about revenue, expense, and rate base components of Staff's proposed adjustments.

In addition, I articulate some of Staff's overarching concerns and summarize public comments received by the Commission in this rate case, pointing to Staff testimony where these issues are examined.

Lastly, I address Cost of Capital components and overall Rate of Return (ROR), going into greater detail regarding Return on Common Equity (ROE). I present Staff's updated ROE modeling results, respond to concerns raised by PGE, and summarize concerns regarding PGE's modeling of the Company's recommended ROE expressed in Opening Testimony by AWEC, CUB and Walmart.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Did you prepare exhibits for this testimony?

A. Yes. I prepared the following exhibits:

Other Supporting Exhibits

Exhibit Staff/2901 .... Value Line (VL) Electric Utilities
Exhibit Staff/2902 ROE – Peer Screen, Dividends, EPS, Hamada Adjustments
Exhibit Staff/2903 .... ROE - Three Stage DCF Modeling
Exhibit Staff/2904 .... ROE - Three Stage DCF Modeling Results
Exhibit Staff/2905 .... ROE – Capital Asset Pricing Model (CAPM)
Exhibit Staff/2906 .... ROE – Gordon Growth, Single Stage DCF
Exhibit Staff/2907 .... Financial News Investors Are Seeing
Exhibit Staff/2908 .... EEI Financial Review
Exhibit Staff/2909 .... Public Comments

1. REVENUE REQUIREMENT IMPACT BY STAFF TOPIC

Q. Please summarize issues that Staff is addressing in its rebuttal testimony and introduce the responsible Staff.

A. See Table 1 below:

TABLE 1 – STAFF RATE CASE REBUTTAL TOPICS

Non-Power Cost Revenue Requirement			Twelve Months Ended 12/31/24	($000)
			Base Cost Incremental Revenue Requirement on the Company's Filed General Rate Case	[redacted]
			After PGE Reply Testimony	[redacted]
			Settled Adjustments	[redacted]
			Outstanding Revenue Requirement Change	[redacted]
Testimony	**Staff**	**Issue**	**Unresolved Revenue Requirement Issues**	**Rev. Req.**
2900	Muldoon	1	Revenue Requirement Impact by Staff Topic	0
		2	Intro to Other Staff's Rebuttal Testimony	0
		3	Key Concerns	0
		4	Summary of Additional Public Comments	0
		5	Overall Rate of Return (ROR) Summary	0
		6	Return on Equity (ROE) w Interest Synch.	(16,955)
3000	Chipanera	1	Revenue Requirement	0
		2	Intervenor Adjustments: State Income Tax Flow Through, and Property Insurance	0
3100	Scala	1	Energy Justice	0
3200	Young/Stevens	1	Change from average of monthly averages to year end in rate base calculation	(15,249)
3300	Stevens	1	PGE's Routine Vegetation Management	[redacted]
		2	Marginal Cost Study	0
		3	Rate Design	0
3400	Dlouhy	1	Proposed Schedule 122 Update	0
3500	Farrell	1	Uncollectible Expense	(5,473)
3600	Jent	1	Wages and Salaries	(555)
		2	Qualifying Facility (QF) Pass Through	0
3700	Dlouhy/Muldoon/ Scala/Stevens	1	Role of Automatic Adjustment Clauses (AAC)	0
		2	The Need for Deferrals with AACs	0
3800	Dlouhy/ Jent/Pileggi	1	Power Cost Adjustment Mechanism (PCAM) Changes	0
3900	Nottingham/ Schearer	1	Changes to Schedules, Rules, Regulations	0
4000	Ankum	1	Fuel Stock (Major only)	(1,564)
		2	CO_2 Allowances	(271)
4100	Bolton/Stevens	1	Line Extensions for Large Customer	0
4200	Shierman	1	Transportation Electrification (TE) Deferrals in UM 1938 and UM 2003	0
	Sub Total of Unresolved Staff Proposed Adjustments			[redacted]
	Total Staff Base Revenue Requirements Change			[redacted]
			Total Reduction from Original Filing	[redacted]

2. INTRODUCTION TO OTHER STAFF'S REBUTTAL TESTIMONY

Q. Please describe the Staff Rebuttal Testimony submitted by Staff on outstanding issues in this rate case.

In Exhibit 3000, Itayi Chipanera, Senior Financial Analyst, discusses revenue requirement, as well as intervenor adjustments regarding state income tax flowthrough and property insurance.

In Exhibit 3100, Michell Scala, Energy Justice Program Manager, provides an Energy Justice overview for this general rate case and discusses five energy justice foci.

In Exhibit 3200 Dr. Bret Stevens, Ph.D., Senior Economist, and **Robert Young**, Managing Director, of economists.com**,** discuss the use of the average of monthly averages in calculations of test year rate base.

In Exhibit 3300, Dr. Stevens reviews PGE's routine vegetation management, marginal cost study and rate spread, and rate design.

In Exhibit 3400, Dr. Dlouhy analyzes examines a proposed Schedule 122 update.

In Exhibit 3500, Bret Farrell, Senior Utility and Energy Analyst, reviews PGE's proposals for uncollectible expense.

In Exhibit 3600, Julie Jent, Senior Utility and Energy Analyst, presents a Qualifying Facility (QF) pass through proposal.

In Exhibit 3700, Dr. Dlouhy, Mr. Muldoon, **Ms. Scala,** and **Mr. Stevens** consider the role of Automatic Adjustment Clauses (AAC) in energy utility regulation and the need for deferrals for AACs.

In Exhibit 3800 Dr. Dlouhy, **Ms. Jent,** and **Ms. Pileggi** discuss PGE's proposed changes to its Power Cost Adjustment Mechanism (PCAM).

In Exhibit 3900, Melissa Nottingham, Consumer Services and Residential Service Protection Fund (RSPF) Manager, and **Scott Shearer**, Analyst, discuss customer interval data, qualified facility monthly charge, submersible transformers, and reconnection rates.

In Exhibit 4000 August Ankum, Chief Economist with **QSI Consulting, Inc**, responds to PGE's Reply Testimony regarding his proposed adjustment to PGE's rate base for Fuel Stock and CO2 allowances.

In Exhibit 4100 Madison Bolton and Dr. Stevens discuss PGE's line extensions for large customers.

In Exhibit 4200 Eric Shierman addresses Transportation Electrification (TE) Deferrals in UM 1938 and UM 2003.

3. KEY CONCERNS

Q. What are Staff's Key Concerns addressed in rebuttal testimony?

A. Staff's key concerns include the impact of a rate increase on PGE's customers, the methodology for calculating rate base, and PGE's increase to its requested rate in Reply Testimony.

RATE IMPACT

Q. Please summarize the Company's Reply Testimony related to rate impact.

A. Staff appreciates PGE's considered response in the Company's Reply Testimony.[1] Regarding timing, PGE asserted, and Staff agrees upon reflection, that PGE could not have anticipated the incremental impacts of inflation given that not that long ago, the U.S. Federal Reserve (Fed) indicated it believed that inflation would be transitory.[2] Further, use of the deferral balance in Docket No. UM 2217 can mitigate the impact of the rate increase.[3]

Q. What is Staff's perspective now?

A. Staff notes PGE's explanation that the Company's requested increase is comparable in size to that found in other electric utility general rate cases in the past year. However, Staff does find public comments the Commission received (explaining that PGE's rates are increasing faster than Oregon utility customer wages) concerning.[4] Staff will review upcoming Rebuttal Testimony of intervenors and monitor customer impacts of aggregated rate changes

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1 *See* Exhibit No. PGE/1600, Pope-Simms/9-11.
2 Federal Reserve Chairman Jerome Powell used the word "transitory" to describe the threat of inflation in 2021 and 2022.
3 *See* Exhibit No. Staff/400, Muldoon/21.
4 *Also see* Exhibit No. Staff/2907, Muldoon/27.

inclusive of this general rate case. Staff will also look to PGE's Surrebuttal Testimony for more detail on PGE's federal grant applications, hoping to see where federal agencies were receptive to PGE's submitted concepts and other indications that PGE's grant applications have traction toward funding or financing guarantees that would lower the cost of new PGE initiatives to Oregon customers.

CALCULATION OF TEST YEAR RATE BASE

Q. Has PGE's Reply Testimony relieved Staff concerns regarding Test Year rate base calculations.

A. No. Robert Young and Dr. Bret Stevens will explain in Exhibit No. Staff/3200 why use of the average-of monthly-test-period-averages is a more appropriate methodology to that proposed by PGE. Staff continues to strongly support reverting to the average-of-monthly-averages in this general rate case, as it represents the average rate base value over the test period when rates are in effect and should be used for purposes of establishing the net income required to provide a return on equity as established by the Commission in this docket.

PGE UPDATES HIGHER THAN INITIAL RATE REQUEST

Q. Did PGE's update its rate request in Reply Testimony?

A. Yes. The rate request in PGE's Reply Testimony is $6.4 million higher than the Company's request in PGE's initial filing, which PGE attributes in part to higher than anticipated inflation.

Q. Is this necessarily something the Commission must disallow?

A. No. While not an attorney, Staff's understanding is that provided Staff and intervenor adjustments adopted by the Commission reduce PGE's rate request to no more than that requested in initial filing, such rates would not violate notice provisions and can be lawfully authorized by the Commission to go into effect January 1, 2024.

4. SUMMARY OF ADDITIONAL PUBLIC COMMENTS RECEIVED

Q. Please summarize the additional public comments received to date since Staff's Opening Testimony in this rate case.

A. Since Staff Published its Opening Testimony, the OPUC has received 84 more public comments regarding this general rate case as of August 4, 2023. These additional comments are provided in Exhibit No. Staff/2909.

TABLE 2 – PRIMARY CONCERNS

Size and Frequency of Increases	Impact of Increase on Those Most in Need
1st	2nd

Certain public comments provided insights into energy justice challenges utility customers are facing. Michelle Scala will address these in her Staff/3100 Rebuttal Testimony. Three commenters felt access to affordable electricity is or should be a right, which would be beyond the scope of this general rate case. One commenter recommends that Renewable Energy Credits and Tax Credits that PGE cannot utilize be sold to control the size of increases needed. Staff understands that PGE is actively examining ways for this to be accomplished while recognizing associated marketing costs.

Q. Does Staff Rebuttal Testimony address comments received?

A. Yes. Comments are addressed throughout Staff's Rebuttal Testimony.

5. OVERALL RATE OF RETURN (ROR)

Q. Please show current Authorized, and Company and Staff positions in this rate case.

A. The following three tables provide that information.

TABLE 3 (Highlights flag referenced information)

PGE Current OPUC Authorized (UE 394 Order Nos. 22-129)			PGE
Component	Percent of Total	Stipulated or Implied Cost	Weighted Average
Long Term Debt	50%	4.125%	2.063%
Preferred Stock	0%	0.0%	0.000%
Common Stock	50%	9.50%	4.750%
	100%		6.813%

TABLE 4[5]

PGE Requested – UE 416		PGE Position as of August 5, 2023		
Component	Percent of Total	Cost	Weighted Average	ROR vs. Current
Long Term Debt	50%	4.485%	2.243%	0.330%
Preferred Stock	0%	0.0%	0.000%	
Common Stock	50%	9.80%	4.900%	
	100%		7.143%	

TABLE 5 with Agreement in Principle on Cost of LT Debt

Staff Proposed – UE 416		Staff Rebuttal Testimony		
Component	Percent of Total	Cost	Weighted Average	ROR vs. Current
Long Term Debt	50%	4.485%	2.243%	0.130%
Preferred Stock	0%	0.0%	0.000%	
Common Stock	50%	9.40%	4.700%	
	100%		6.943%	

5 *See* PGE/2400, Villadsen-Liddle/3 for PGE's recommended 9.8% ROE.

6. RETURN ON EQUITY (ROE)

Q. What range of reasonable ROEs does Staff recommend, and within that range, what point ROE?

A. For reasons discussed below, Staff has changed the recommendation regarding ROE initially presented in this case. In opening testimony, Staff recommended a point ROE estimate of 9.0 percent within a range of reasonable ROEs of 8.83 percent to 9.10 percent. After updating its analysis with new data, Staff now recommends a **point ROE** estimate of **9.4 percent** within a range of reasonable ROEs of 9.13 percent to 9.53. As with Staff's initial recommendation, the range and point estimate are derived from Staff's two separate Three-Stage Discounted-Cash-Flow (DCF) models, which are the models the Commission has traditionally favored for ROE analysis.

Q. Does your recommended ROE meet appropriate standards?

A. Yes. The 9.4 percent ROE Staff recommends is appropriate for overall rates that are reflective of forward looking conditions and meets the *Hope* and *Bluefield* standards, as well as the requirements of Oregon Revised Statute (ORS) 756.040.[6] Staff 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

[6] *See Federal Power Commission v. Hope Natural Electric Co*., 320 U.S. 591 (1944) and *Bluefield* Water *Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[7]

VALID PGE CRITICISM

Q. What were the PGE criticisms of Staff's ROE Modeling that underlie some of the updates to Staff's analysis?

A. PGE noted that A) Staff's work did not capture market inputs properly reflective of significant interest rate tightening by the U.S. (Fed) and B) was not appropriately informed by state commission Federal Reserve general rate case ROE decisions in the first half of 2023.

Q. How did Staff address those concerns?

A. Staff updated its ROE models to capture current data as presented in Exhibits Staff/2902-2906. While this was a significant amount of work, it now brings Staff ROE modeling contemporaneous with best current financial market information.

Staff also analyzed decisions from other state commissions regarding ROEs. "The average ROE authorized for electric utilities was 9.56% for rate cases decided in the first half of 2023, above the 9.54% average observed in full year 2022."[8] This information only became fully available July 31, 2023. The ability of these models to be informed by best available information is part of the reason for the Commission reliance upon them. Now that Staff's three-

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

[8] See S&P Global, Regulatory Research Associates – RRA Regulatory Focus – "Major Rate Case Decisions" of July 31, 2023, and *see also* related financial news reproduced in Exhibit No. Staff/2907, Muldoon/7,10,22, 55.

stage discounted cash flow modeling captures best available current information, the upper end of Staff's range of reasonable ROEs is only 3 basis points lower than the national average.

Interestingly, in the first half of 2023, State Commissions awarded natural gas utilities on average a 10 bps higher ROE than like decisions for electric utilities. It may be that the movement toward larger electric vehicles and electrify everything is shifting the historical perspective that electric utilities were riskier and merited 10 bps higher ROE on average than natural gas utilities.[9] That no longer seems to be the case and perhaps electric utilities ROE are being set lower than those for natural gas utilities.

STAFF ROE MODELING REFRESHMENT

Q. Did Staff update its review for any changes in inputs to its peer screening.

A. Yes. Staff used current information to update its peer screening. This did not result in a different peer group or sensitivity peer group for Staff. It is unclear whether PGE has refreshed its modeling inputs.

Q. Did Staff update dividend and earnings-per-share (EPS) data to ensure it is accurately capturing current market trends therein.

A. Yes. Staff fully updated these inputs.

Q. Did Staff update electric utility referent stock prices to the current period to ensure it is properly capturing stock price appreciation.

[9] *See* Exhibit No. Staff/2907, Muldoon/1,55.

A. Yes. Staff fully updated these inputs to be current as of August 1, 2023.

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

A. See Table 6 below for the results from Staff's updated three stage DCF modeling. Highlights flag referenced information.

TABLE 6 – RESULTS OF STAFF'S 3-STAGE DCF MODELING[10]

Best Fit Range of Reasonable ROEs	9.01%	**to**	9.41%	**ROE**	
Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward				**12.5**	bps
	9.13%	**to**	9.53%	**ROE**	
	Midpoint	9.3%	**ROE**	**Testimony**	
Staff Point ROE Recommendation:		**9.4%**			

CAPM and Single Stage DCF point to the upper range of Staff's Three Stage DCF Modeling Results

Supporting Exhibit Staff/2904, Muldoon/1 shows step-by-step how Staff's Hamada adjusted Three-Stage DCF modeling results, using Staff peers and growth rates, generates a higher recommended ROE than using PGE's peer electric utility group.

Q. Did you perform a check on the results of Staff's Three-Stage DCF models?

A. Yes. Staff employed <u>two</u> simpler models to check the reasonableness of its findings:

1. A Single-Stage DCF or Gordon Growth Model; and,
2. A Capital Asset Pricing Model (CAPM).

Q. What results did these models generate?

A. The Gordon Growth Model generated a mean ROE of 9.6 percent using Staff's peer electric utilities and 9.0 percent with the Company's peer electric utilities.

The CAPM generated a mean ROE of 9.7 percent using Staff's peer

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[10] *See* Exhibit Staff/404, Muldoon/1 for the results of Staff three-stage DCF modeling.

electric utilities and 9.5 percent with the Company's peer electric utilities, each relying on 10-year geometric market returns and a 10-year U.S. Treasury (UST) as a proxy for the R_f in calculating a Market Risk Premium (MRP) for holding generally riskier stocks than bonds.

Alternatively, CAPM generated a mean ROE of 9.1 percent using Staff's peer electric utilities and 8.9 percent with the Company's peer electric utilities, each relying on 30-year geometric market returns and a 30-year U.S. Treasury (UST) as a proxy for the Risk-Free Rate (R_f) in calculating an MRP.

Based on these checks, pointing to top of range Staff finds that the point estimate for ROE in Staff's range of reasonable ROEs generated by its two separate Three-Stage DCF models should be near the top of modeling results reflective of the above checks on reasonableness. However, it need not be at the very top 9.5 percent of Staff's range of reasonable ROEs.

Q. Did Staff use robust and proven analytical methodologies?

A. Yes. Staff's methods are robust, proven, and parallel Staff's work for many years. The Commission, for example, expressly relies on the multi-stage DCF to determine the range of ROEs and relies on CAPM and risk premium models to check the reasonableness of results. This can be seen in Order No. 22-129 in PGE Docket No. UE 394 as well as in Order No. 20-473 in PAC Docket No. UE 374.

RESPONSE TO OTHER PGE CRITICISM OF STAFF ROE MODELING

Q. Aside from the PGE concerns addressed in Staff's updated analysis, does PGE have other concerns regarding Staff's ROE analysis?

A. Yes. PGE's witnesses state their "key concern" is that Staff's ROE estimate relies on a single model, the DCF model.[11] Somewhat inconsistently, PGE also asserts that Staff inappropriately relies on a CAPM that uses a geometric average MRP rather than an MRP based on an arithmetic average.

PGE also objects to Staff's selection of peer utilities for its DCF modeling. PGE asserts Staff's inclusion of distribution-only utilities introduces downward bias.[12] Second, PGE is concerned that Staff restricts peer utilities to those that have Standard and Poor's or Moody's credit ratings like PGE's.[13] PGE actually says, "there is very little difference in the default risk of companies that have a BBB or an A credit rating."[14] This is quite extraordinary as credit ratings also reflect assessment of the regulatory environment within which an energy utility operates.

Q. Does PGE's argument that Staff should relax the credit rating criteria for peer selection for its DCF modeling undermine PGE's arguments that PGE is riskier than peer utilities?

A. Yes. It is also rather extraordinary how PGE's argument refutes its own position regarding the relative risk of the Company so effectively. In any event, Staff disagrees that relaxing its criteria for peer companies is appropriate. Staff believes its selection criteria resulted in an appropriate

[11] *See* PGE Reply Testimony Exhibit No. PGE/2400, Villadsen-Liddle/5
[12] *See* PGE Reply Testimony Exhibit No. PGE/2400, Villadsen-Liddle/14.
[13] Id.
[14] Id.

pool of companies for its ROE analysis. PGE emphasizes a distinction between vertically integrated and distribution only utilities, but notably, Staff still does not achieve the higher range of ROE estimates when Staff substitutes PGE's selection of peer utilities for those selected by Staff. The ROE estimates are higher using Staff's peer group than with PGE's selection of peer group utilities.

Q. What is your response to PGE's arguments that Staff inappropriately relies only on a DCF model and inappropriately relies on a CAPM model using a geometric average market risk premium?

A. First, Staff does not rely solely on a single DCF model for its ROE recommendation. In fact, Staff used two different multi-stage DCF models to determine its point estimate ROE and a reasonable range of ROEs. And, as PGE acknowledges, at least implicitly, Staff relied on a CAPM and Gordon Growth model to validate the results obtained by its Three-State DCF models. Staff's analysis is consistent with Commission precedent that expressly favors the multi-stage DCF to determine the appropriate range of ROEs and relies on CAPM and Risk Premium models to check the reasonableness of results.[15]

[15] Docket No. UE 394, Order No. 22-129, *First, Second, Third, And Fourth Partial Stipulations Adopted; Application For PGE General Rate Revision Approved As Revised* (April 25, 2022); Docket No, UE 374 Order No. 20-473 in PAC Docket *Partial Stipulation Adopted; Application For PAC General Rate Revision Approved As Revised* (Dec. 18, 2020); Docket No. UE 115, Order No. 01-777, *In the Matter of PGE's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149* (Aug. 31, 2001); Docket No. UE 116, Order No. 01-787 *In the Matter of PAC's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149* (March 19, 2002).

PGE's argument regarding use of a geometric average to determine the market risk premium rather than the arithmetic average is the inverse of Staff's criticism of PGE's use of an arithmetic average. Generally, an arithmetic average is only appropriate for short term investments.

Q. What methodology (arithmetic or geometric) has the Commission determined is the appropriate methodology to determining a market risk premium for the calculation of ROE using CAPM.

A. The Commission has stated:

> "A **geometric average** should be used to derive the market risk premium when CAPM is focused on a holding period greater than one year." [16]

Q. Has the Commission further considered which CAPM risk premium methodology is best for investments to be held for a period greater than a year?

A. Yes. The Commission has stated:

> The **geometric mean**, …, is the best estimate of the ending value of an investment over multiple periods.[17][18]

Q. In that proceeding did a Mr. Morin provide cost of capital testimony for the company?

A. Yes. The Commission heard Mr. Morin's preference for use of an arithmetic rather than a geometric mean in the calculation of a market risk premium in performing a CAPM to determine an appropriate ROE.[19]

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16 OPUC Docket No. UT 43, Order No. 87–406, PAC NW Bell. Entered March 31, 1987, p 31.

17 OPUC Docket No. UT 113, Order 94-336 GTE NW, Entered February 22, 1994, p 14.

18 Mark Kritzman, "What Practitioners Need to Know About Risk and Return" Financial Analysis Journal May/June 1993, p 15.

19 This testimony was provided in Exhibit No. GTE-NW/22, Morin/32.

Q. Was the Commission persuaded by Mr. Morin.

A. No. The Commission determined as noted above that the geometric mean was to be used for CAPM market risk premium calculations.

Q. Why does Staff not rely more heavily on risk premium ROE modeling?

A. Consider taking a very long run tracking of Stock and Bond returns and parsing it into three decade increments with different starting years. A quarter of the time, persons living in those decades would have seen bonds outperform stocks for that decade. For example, in the 30-year period ending in 2011, bond returns outperformed stock returns. Consider PGE general rate case Docket No. UE 115 filed October 2, 2000. Sometimes, a presumption that Stocks will dramatically outperform bonds is going to fall very flat, and potentially for a decade or more.[20]

STAFF CONCERNS WITH PGE'S ROE MODELING

Q. Does Staff agree with PGE's assertion that the Company's requested ROE of 9.8 percent is still reasonable?

A. No. While PGE has contorted Staff and intervenor models, Staff observes no new justification for PGE's excessive ROE request.

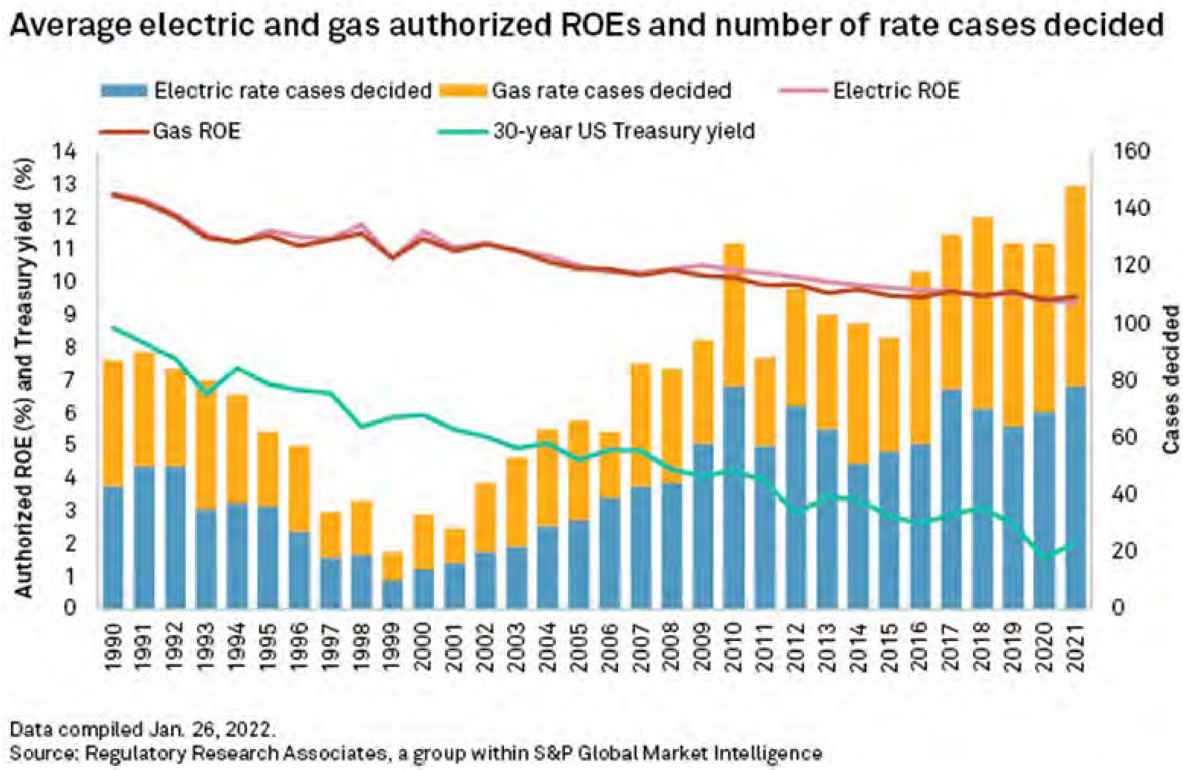
Q. Does PGE fail to consider important trends in its ROE Analysis?

A. Yes. First, there is a macro downward glide path for ROE. Figure 1 below is not linear and may fluctuate through these uncertainties, but long-run GDP

[20] *See* Exhibit No. Staff/2907, Muldoon/4, 41, 42, and 45.

growth rates are mostly determined by the long future U.S. working age population and its productivity both facing declines over the long-run.[21]

FIGURE 1 – Downward Glide Path of Utility ROES[22]



Second, PGE emphasizes the Fed's recent increases of interest rates to fight inflation, while remaining silent on the fact that interest rates declined from double digit to near zero prior, on the one hand, and that the Fed targets two percent inflation, on the other. If the Fed intentions are realized this could graphically look like Figure 2 below.[23]

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[21] *See* Exhibit Staff/408, Muldoon/1, 20 for pertinent population growth rates.

[22] Published by Regulatory Research Associates (RRA), an affiliate of S&P Global Market Intelligence (Feb. 10, 2022).

[23] Board of Governors of the Federal Reserve System, *Market Yield on U.S. Treasury Securities at 10-Year Constant Maturity*, Quoted on an Investment Basis [DGS10] (Aug. 17, 2023), available at https://fred.stlouisfed.org/series/DGS10#0.

FIGURE 2 – MACRO Downward Glide Path of Interest Rates

The key idea illustrated above is that we are in a macro decline in interest rates, within which we have smaller potentially short-term upward movement of lesser magnitude than the macro decline. That macro decline in interest rates corresponds to a lagged decline in authorized ROEs shown earlier in Figure 1.

Q. Why does Staff urge the Commission to take a cautious stance when considering any increase in PGE's ROE?

A. According to Regulatory Research Associates (RRA), since 1990 electric and electric utility authorized ROEs have declined as the 30-year US Treasury (UST) has also declined. While the Fed is now raising interest rates, there is considerable uncertainty whether the Fed may need to decrease interest rates as soon as inflation is under better control, or the U.S. economy experiences duress due to such a rapid tightening cycle.

Further, there seems to be significant delay or lag in recognizing falling interest rates and making appropriate reductions to ROE in comparison to PGE's request for immediate upward increase in ROE based on rising interest rates that may be quite temporary. That is of concern because the time horizon for ROE is a forward looking 30 years. Staff still sees low federal and other estimates of long-run U.S. GDP growth rates, which still bound considerations of most appropriate cost of capital. U.S. GDP in turn is constrained by U.S. Working age population, workplace participation and productivity, all facing challenges.[24]

Q. Should PGE presume the Fed will fail to meet its goals?

A. "*Don't fight the Fed*" is a mantra that cautions investors to align investments with the current monetary policies of the Fed rather than against them. While the Fed may have been surprised by persistent inflation, recent Fed interest rate actions have greatly reduced current inflation. In June the Consumer Price Index (CPI) climbed 3.0 percent from a year earlier. This is a marked decrease in inflation from the June 2022 peak of 9.1 percent.[25] Staff suggests that exercising caution now would be a better course than betting the Fed cannot achieve another percent reduction in inflation before relaxing monetary policy.

Q. Does PGE admit to using an arithmetic rather than a geometric market risk premium?

A. Yes. There are many examples of this in PGE's testimony.[26]. As PGE is likely aware, authors of primary teaching finance textbooks such as Bodie Kane and Marcus, 2002, p 810-811; Brealey and Myers, 2003 p 156-157; and Ross, Westerfield, and Jaffe 2002 p 232-233 did much of the heavy

24 Exhibit No. Staff/2907 Muldoon 29,34, and 36.
25 *See* Nick Timiraos "Fed Lifts Rates to Highest Level in 22 Years" Wall Street Journal (WSJ) (July 27, 2023).
26 PGE Reply Testimony Exhibit No. PGE/2400, Villadsen-Liddle/18-22.

lifting for their texts some time ago when they agreed with PGE's position, but they continued academically to look at arithmetic vs geometric market returns. It is now known that arithmetic average always results in an upward bias, and that bias can be substantial.[27] [28] [29] [30]

The nature of market returns is presented in an approachable way by Burton Malkiel in his book, "A Random Walk Down Wall Street". In simplest form, market returns are not readily predictable and importantly go down as well as up. When an investor loses money, as occurred for many investors during and since the pandemic, that money is gone and going forward there is less of an investment earning returns.

Other authors looking at security returns find that given the weight of evidence of mean reversion in stock returns, there is a strong case for the use of a geometric mean.[31] Finance journal articles looking at alternative ways to look at internal rate of return for securities also appear to favor a geometric rather than an arithmetic mean.[32]

27 Eric Jacquier, Alex Kane, and Alan J. Marcus, "Geometric or Arithmetic Mean: A Reconsideration".

28 *The Economic Times,* "Use Geometric Mean to Calculate Your Investment Returns." *(*Dec. 16,2019), https://slo.idm.oclc.org/link.gale.com/apps/doc/A608761514/ITBC?u=sale38182&sid=bookmark-ITBC&xid=754f368a.

29 Daniel C. Indro and Wayne Y. Lee," Biases in Arithmetic and Geometric averages as Estimates of Long-Run Expected Returns and Risk Premia" 26 Financial Management 4.

30 Leippold, Markus and Vanini, Paolo and Trojani, Fabio, *A Geometric Approach to Multiperiod Mean Variance Optimization of Assets and Liabilities* (April 2002). Univ. of Southern Switzerland Working Paper, available at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=289601 - paper-citations-widget.

31 Adrian Buckley, *An introduction to security returns*, 5:3 The Euro. J. of Fin. 165-180, (1999).

32 P. J. Barry and L. J. Robison, *Economic Rates of Return and Investment Analysis*, 59 The Engineering Economist 231–236 (2014).

Further, current authors also explain in approachable terms how an investor can markedly overstate forward looking market returns by presuming that the high stock returns of about seven percent from the mid-1920s to the mid-1990s would be representative of likely future returns.[33] PGE's modeling on ROE does not appear informed by that caution. A more technical analysis is provided by Jacquier, Kane and Marcus, though with the same conclusion, namely that, "A consensus is already emerging that the 1926-2002 historical average returns on such broad market indexes as the S&P 500 are probably higher than likely future performance."[34]

Staff also invites PGE to explain in the Company's Surrebuttal Testimony whether its expected market returns in modeling ROE are consistent with the Company's responses to Standard Data Requests 59 and 60 regarding Expected Return on Assets (EROA) for each of PGE Pensions and Post Retirement Medical Expenses. If the stock market return components of EROA for PGE Pensions and Post-Retirement Medical Expenses are lower than expected market returns in PGE's ROE modeling, the Company could take that opportunity to explain why this is reasonable.

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[33] Glenn Ruffenach, *William Bernstein on Investors' Biggest* Risk, WSJ (Aug. 11, 2023) reproduced in Exhibit No. Staff/2907, Muldoon/65.

[34] Eric Jcquier, Alex Kane, and Alan J. Marcus, *Geometric or Arithmetic Mean: A Reconsideration*, Fin. Analyst J., 59(6), 46-53 (2003).

AWEC-CUB ISSUES AND CONCERNS WITH PGE ROE MODELING

Q. Are the Alliance of Western Energy Consumers (AWEC) and the Oregon Citizens' Utility Board (CUB and, collectively AWEC-CUB) in support of PGE's modeling treatment regarding ROE?

A. No. AWEC-CUB criticize PGE's ROE modeling, observing:[35]

1. The After-Tax Weighted Average Cost of Capital (ATWACC) adjustment is unnecessary and does not have wide regulatory acceptance.
2. The upper end of PGE's recommended range and PGE's point estimate rests solely on the inclusion of financial leverage adjustments.
3. PGE inappropriately excluded outlier results. PGE should have measured the proxy group's median results to mitigate the effect of outliers.
4. For PGE's CAPM analysis, PGE includes both an ATWACC adjustment, and alternatively a leveraged beta adjustment to the CAPM results.
5. PGE projected risk-free rate of 4.05% is excessive and not reflective of current interest rate projections.
6. PGE's Value Line betas are based on five years of historical stock prices and are significantly being impacted by the spike in volatility due to the pandemic and its impact on the market in early 2020. PGE failed to consider a more normalized estimate of beta.
7. PGE also relies on an ECAPM analysis and includes adjustments for her ATWACC and leveraged beta methods. Further PGE's ECAPM analysis is miscalculated because the Company uses adjusted betas within an ECAPM format. This is inappropriate because an adjusted beta accomplishes the same thing as an ECAPM analysis. Both levelize the security market line in measuring a fair ROE based on a given level of systematic risk or beta risk. PGE's ECAPM analysis double counts the increase in the CAPM return estimates for companies with betas less than one, which reflects PGE's proxy group and PGE in this case.
8. PGE's assertion that PGE is of higher risk than her sample companies is incomplete, inaccurate, and should be ignored.

Q. Does AWEC-CUB support PGE's ATWACC methodology?

35 *See* AWEC-CUB Opening Testimony concerns Exhibit No. AWEC-CUB/100, Walters/55-56.

A. No. They state that the ATWACC methodology is poor regulatory policy and should be rejected for several reasons: [36]

1. It does not produce clear and transparent objectives for management to use that will accomplish the objective of minimizing its overall rate of return while preserving its financial integrity. It ignores a utility's need for capital discipline, treating it as it would an unregulated utility affiliate. Therefore, a regulatory commission cannot oversee the reasonableness and prudence of management decisions in managing its capital structure. Under the ATWACC theory, management's decisions to manage its capital structure can be skewed by changes in market value which change the market value capitalization mix. Management simply has no control over the market value capital structure, but it does have control over the book value capital structure. As such, setting the rate of return and measuring risk based on book value capital structure creates a more transparent path for regulatory oversight of management's effort to maintain a balanced and reasonable capital structure.

2. The ATWACC introduces significant additional instability and unreliability into the utility's cost of service and tariff rates. Book value capital structure weights permit the utility to hedge or lock-in a large portion of capital market costs in arriving at the rate of return used to set rates. This rate of return cost hedge stabilizes the utility's cost of service, which in turn helps stabilize utility rates. A stable method of setting rates also allows investors to more accurately assess the future earnings and cash flow outlooks for the utility, which will reduce the business risk of the utility. The ATWACC, on the other hand, will produce an overall rate of return which will change based on both changes to market value capital structure weights and also based on changes to market capital costs. Hence, a major component of the cost structure of the utility (i.e., the overall rate of return) will vary based on market forces from rate case to rate case. This rate of return variability will introduce significant instability in the utility's cost of service (via rate of return changes) and hence instability in tariff rates. Introducing additional instability and unreliability in the utility's cost structure and rates will not benefit either investors or ratepayers.

3. The ATWACC artificially increases rates to produce an excessive ROE opportunity for utility investors, as if the utility were an unregulated affiliate. Inflating utility's rates to provide this excessive earnings opportunity is unjust and unreasonable to ratepayers and should be rejected.

[36] Exhibit No. AWEC-CUB/100, Walters/57.

Q. Does Staff agree with AWEC-CUB on this issue?

A. Yes.

Q. Does AWEC-CUB have concerns with PGE's Discounted Cash Flow (DCF) analysis?

A. Yes. In addition to the inclusion of her financial leverage adjustments, they are concerned that PGE failed to measure the proxy group median results instead of removing the results PGE deemed to be too low for consideration. The median result of PGE's constant growth DCF is 9.9% and the median of PGE's multi-stage DCF is 8.4%. The midpoint of these estimates is 9.15%.[37]

Q. Does AWEC-CUB have concerns with PGE's Capital Asset Pricing Model (CAPM)?

A. Yes. In addition to PGE's various leverage adjustments, they are concerned are that PGE's average Value Line beta of 0.884 is still being impacted by the market fallout caused the pandemic in early 2020 and not reflective of current investor expectations, and her projected 20-year Treasury yield of 4.05% is significantly overstated.[38]

Q. Does Staff agree with AWEC-CUB on this issue?

A. Yes.

Q. Does AWEC-CUB have concerns with PGE's projected Treasury yield of 4.05%?

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[37] AWEC-CUB/100, Walters/59.
[38] AWEC-CUB/100, Walters/61.

A. Yes. They state that projected risk-free rate of 4.05% is based on a projected 10-year Treasury yield of 3.55% plus a 0.50% spread to account for the differences between the 20-year yield over the 10-year yield. More recent projections for the 10-year Treasury yield are 3.4%. Importantly, the projected 30-year Treasury yield is 3.7%. AWEC-CUB find that PGE assumes that the 20-year yield will exceed the 30-year yield by 35 basis points. Such an assumption is unreasonable and should be rejected. A more reasonable estimate of the projected 20-year Treasury yield would be somewhere between the projected yields for the 10-year Treasury (3.4%) and the 30-yearTreasury (3.7%). The midpoint of these projections is 3.55%.[39]

Q. Does Staff agree with AWEC-CUB on this issue?

A. Yes.

Q. Are AWEC and CUB concerned with PGE's application of leverage beta?

A. Yes. They state that PGE's financial leverage adjustments are generally not accepted in establishing a fair ROE in regulated rate-setting proceedings such as this one.[40]

Q. Does Staff agree with AWEC-CUB on this issue?

A. Yes.

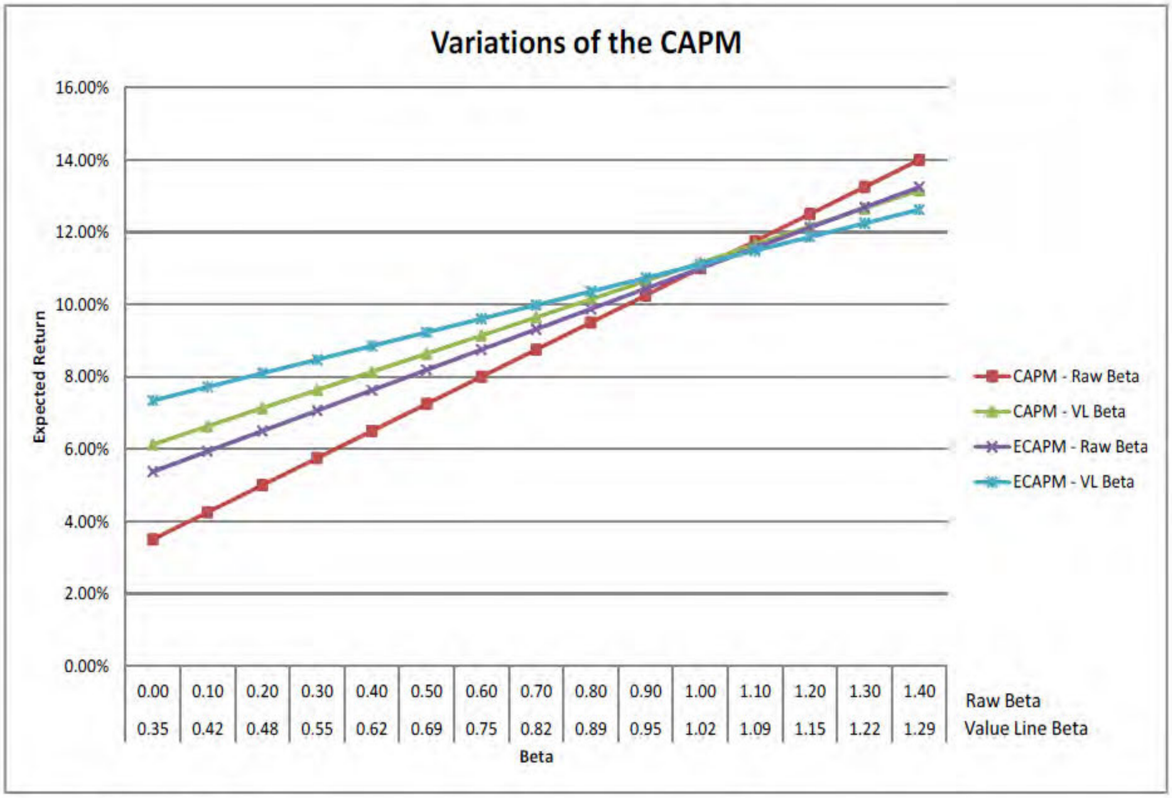
Q. Does AWEC-CUB have concerns with PGE's ECAPM return estimates?

[39] AWEC-CUB Opening Testimony, Exhibit No. AWEC-CUB/100, Walters/61-62.
[40] AWEC-CUB Opening Testimony, Exhibit No. AWEC-CUB/100, Walters/62.

A. Yes. They note that PGE reliance on the Company's ECAPM return estimates are inappropriate. Specifically, they are concerned that PGE included an adjusted beta within the Company's ECAPM studies. This adjustment is inconsistent with the academic research supporting the development of an ECAPM methodology. Bottom line, using adjusted betas within an ECAPM study double counts the purpose of the ECAPM study – that is, to flatten the security market line and increase a CAPM return estimate for companies with betas less than one, and decrease the CAPM return estimate for betas greater than one.

The ECAPM will raise the intercept point of the security market line and flatten the slope which has the effect of increasing CAPM return estimates for companies with betas less than one, and decreasing the CAPM return estimates for companies with betas greater than one. Importantly, however, the use of an adjusted beta such as those published by Value Line, produces comparable adjustments to the security market line and CAPM return estimate. In effect, using an adjusted beta within an ECAPM study has the effect of a double adjustment to the slope and intercept of the security market line. This is illustrated in AWEC-CUB Figure CCW-5 below.

FIGURE CCW-5



Assumptions:
Market Risk Premium is 7.50%
Risk-Free Rate is 3.50%

As shown in Figure CCW-5 above, the CAPM using a Value Line beta, versus a CAPM using a raw-beta shows that the Value Line beta raises the intercept slope and flattens the security market line. Further, the ECAPM using a raw beta, and an ECAPM using a Value Line beta, have a magnified effect of increasing the intercept slope and further flattening the security market line.

AWEC-CUB state that there is simply no legitimate basis to use an adjusted beta within an ECAPM because they are designed to produce the same effect on the CAPM return estimate.[41]

Q. Does Staff agree with AWEC-CUB on this issue?

A. Yes.

Q. Does AWEC-CUB have observations regarding PGE's risk premium analysis?

A. Yes. AWEC-CUB believe PGE's projected risk-free rate and projected risk premium are both too high. They note that PGE's projected risk-free rate of 4.05% is based on a projected 10-year Treasury yield of 3.55% plus a 0.50% spread to account for the differences between the 20-year yield over the 10-year yield. More recent projections for the 10-year Treasury yield are 3.4%. Importantly, the projected 30-year Treasury yield is 3.7%. PGE assumes that the 20-year yield will exceed the 30-year yield by 35 basis points. Such an assumption is unreasonable and should be rejected. AWEC-CUB state that a more reasonable estimate of the projected 20-year Treasury yield would be somewhere between the projection yields for the 10-year Treasury (3.4%) and the 30-year Treasury (3.7%).

AWEC-CUB further state that a more reasonable estimate of the projected 20-year yield would produce a more reasonable result. Assuming a 20-year yield of 3.55%, which is the midpoint of the projections for the 10-year Treasury (3.4%) and the 30-year Treasury (3.7%) yields, PGE's

[41] AWEC-CUB Opening Testimony, Exhibit No. AWEC -CUB/100, Walters/63-64.

regression model would produce an ROE estimate of 10.16%, which compares to PGE's risk premium recommendation of 10.4%. AWEC-CUB suggest that a ROE estimate for the risk premium method using 30-year Treasury yields is 9.74%. The midpoint of 10.16% and 9.74% is 9.95%.[42]

Q. Does Staff agree with AWEC-CUB on this issue?

A. Yes.

Q. Does AWEC-CUB believe PGE accurately assessed the risk of PGE relative to the sample?

A. No. AWEC-CUB say that PGE has cherry-picked risks potentially faced by PGE without considering other unique risks faced by the proxy group companies. They recommend the Commission ignore PGE's concerns about these particular risks.

First, AWEC-CUB notes that to the extent ratings agencies deemed these particular risks detrimental to PGE, ratings agencies would have taken them into consideration, and they would be reflected in PGE's credit ratings. Rather, PGE's ratings from both S&P and Moody's are identical to, or higher than those of PGE's proxy group. S&P and other credit rating agencies go through great detail analysis in assessing a utility's business risk and financial risk in order to evaluate their assessment of its total investment risk. AWEC-CUB testimony states that PGE's total risk is likely less than that of the proxy group, not more. They summarize that PGE's argument that the Company is of higher risk is misleading and should be ignored.

42 AWEC-CUB Opening Testimony, Exhibit No. AWEC-CUB/100, Walters/65-66.

CUB and AWEC emphasize that in regard to the CAPM, investors are not compensated for taking on company-specific risks, as those risks can be eliminated through portfolio diversification. Institutional investors are the largest holders of utility stocks in general. Examples of institutional investors include, but are not limited to, pension funds, endowments, and mutual funds. Even if one were to accept PGE's misleading assertion that PGE is of higher risk, to suggest these investors are not well-diversified and somehow need to be compensated for taking on company-specific risks would be in error and violate the CAPM.

Based on the above considerations, CUB and AWEC find PGE's conclusion that the Company is of higher risk relative to PGE's sample companies is unfounded and should be rejected.[43]

Q. Does Staff agree with all aspects of AWEC-CUB ROE modeling and associated findings?

A. No. However, Staff does find that AWEC-CUB and Walmart's recommendation that the Commission reauthorize the current 9.5 percent ROE for PGE is a viable alternative to Staff's recommended 9.4 percent point ROE should the Commission chose to wait for better information about how well Fed interest rate increases mitigate inflation.

[43] AWEC-CUB Opening Testimony, Exhibit No. AWEC-CUB/100, Walters/66-67.

CONCLUSION

Q. What primary summary recommendation do those offering public comments make to the Commission?

A. The frequency and magnitude of PGE's rate increases is straining Oregon utility customers' means and is of concern to those sharing their personal experiences with the Commission.

Q. What is Staff's recommendation regarding ROE?

A. Staff recommends that the Commission adopt a point ROE of 9.4 percent consistent with the findings herein within a range of reasonable ROEs between 9.13 percent and 9.53 percent. Staff took what it believed were valid PGE concerns to heart and updated the inputs of Staff's ROE modeling to be reflective of most current market conditions after Fed interest rate actions to control inflation.

Q. What Rate of Return (ROR) is generated by the Staff's aggregated Cost of Capital recommendations on Capital Structure, ROE, and Cost of Long-Term Debt?

A. Staff's calculations generate a 6.943 percent Overall Rate of Return (ROR), an increase of 13 bps over that currently authorized. As Capital Structure and Cost of LT Debt are settled, determination of overall ROR hinges on consideration of most appropriate point ROE as shown in Table 6.

Q. Does Staff offer an alternative to its primary recommendation?

A. Yes. Both AWEC-CUB and Walmart recommend in Opening Testimony that the Commission maintain PGE's currently authorized 9.5 percent ROE, which would result in a ROR of 6.993. That would be at the upper end of Staff's recommended range of reasonable ROEs. It would also be in line with state regulatory commission rate case decisions regarding electric utility ROEs in the first half of this year.

Q. Does that conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2901

Value Line (VL)
Electric Utilities

August 22, 2023

ELECTRIC UTILITY (EAST) INDUSTRY

All major electric utilities located in the Eastern region of the United States are reviewed in this Issue; Western-based electrics, in Issue 11; and the remaining Industry participants, in Issue 5. Since our last review of the Electric Utility (East) Industry three months ago, the 35 electric utilities we cover in *The Value Line Investment Survey* are up 1.8% on average, compared to a 3.7% gain in the S&P 500 for the same period. For a lengthier perspective, the group held up quite well over the course of 2022, down just 2% on average, while outperforming the S&P 500 by 17 percentage points.

Electrics have, however, experienced their share of volatility over the past several months, faring well when the market is concerned about economic weakness, as the group is considered to be resilient during downturns in the economy. Utility stocks have also displayed vulnerability when the market concern of the day is rising interest rates and inflation. There really is no silver lining for these stocks during periods characterized by rising interest rates.

There was about a four-week stretch from mid-September to mid-October when utilities and other interest-rate sensitive stocks sold off much more severely than the broad market. *The Value Line Utility Index* during that stretch plummeted 18.5%, underperforming the S&P 500 by 5.5 percentage points. From their respective October nadirs, utilities as a group are up 9.8% versus a 16.5% rally in the S&P 500. Investors should note that this group is likely to underperform the broad market during the next economic upswing.

Recent 3- to 5-year annual total return prospects for electric utility stocks look comparable to what we've seen for the past year or so. The median level for the 35 electrics we cover is 8.6%. Although there is a generally reduced-risk level in owning utilities, given that they're regulated monopolies, we would still like to see 10%-11% annual total return potential for the haul to 2026-2028 in a given utility stock in order to recommend investors purchase the issue. That level is roughly in line with the long-term returns of the broad market. Meanwhile, the median forward 12-month dividend yield for this group is 3.65% at present, 135 basis points above the average of all dividend-paying stocks covered by *Value Line*.

Utility Portfolio Considerations

We highlighted the stretch of relative weakness above because our greatest concern with owning utilities over the long haul is how they'll perform for investors during a secular upturn in interest rates. As a point of reference, *Consolidated Edison*, a bellwether stock for this industry, traded at a price-to-earnings (P/E) ratio that was just above half of the market level, while sporting a hefty 9% dividend yield during the last secular peak in interest rates and inflation (the early to mid-1980s).

In recent years, *ConEd* stock has garnered a market-level P/E ratio with a dividend yield in the 3.5%-4.0% range. Currently the stock carries an earnings multiple of 20.4, a relative P/E of 1.21 and a dividend yield of 3.3%. The takeaway here is that when rates are rising, utility valuations generally fall in order to keep dividend yields competitive with rising bond yields.

INDUSTRY TIMELINESS: 90 (of 93)

We think utility investors can help their cause by being disciplined buyers. It's rare to see a utility stock continually rise in value with no opportunities to enter on corrections along the way. The midpoint of the annual total return projections, which are based on the 3- to 5-year Target Price Range and dividend estimates, should ideally be 11% or higher at entry for most utilities under our review. A little lower is alright for a select few of the faster growing companies. Emphasizing utilities with higher dividend growth than that of the industry's projected average of 4.8% is also recommended.

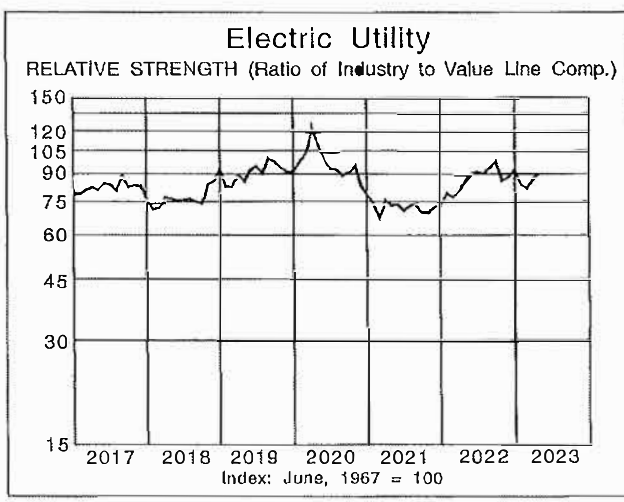
Topical And Concluding Remarks

The recent macro environment is a challenge for most electrics. The main difficulties are overall inflation, rising interest rates, and stubbornly high commodity energy prices relative to where they were a few years ago. We can also add rising pension expense to the list, at least for this year, because last year's market declines in bonds and stocks require higher retirement contributions be made this year for many companies.

Due to how the regulatory mechanisms work in this industry, some of this added expense can rapidly be passed on to customers. (It varies by state.) Many costs must instead go through a filed rate case to be reviewed by a state regulatory panel, which can be an onerous and lengthy process. This "regulatory lag" can accumulate over time, causing some companies to perennially under earn their allowable return on equity. That will surely result in lower earnings and dividend growth compared to that of utilities who achieve their allowable rate of return.

Although this group at first glance appears to be homogeneous, the individual electrics vary in many regards that must be accounted for. Regulatory climate and the overall health of the underlying regional and local economies within a utility's service territory are huge difference makers. States making an aggressive transition to "green" energy will generate a lot of invested capital opportunities for utilities in those territories. This should also be a difference maker. Utility investors need to be very selective in their holdings.

Anthony J. Glennon



All major companies in the Electric Utility (Central) Industry reported first-quarter financial results and are reviewed in this Issue.

Since our last review of the Electric Utility (Central) Industry three months ago, nearly all of the stocks we cover have declined in value.

Utility stocks have experienced high volatility over the past several months due to market concern, the interest rate environment, and increased costs. Many of these stocks are currently trading at double-digit discounts to historical valuations, and as the gap between the average utility dividend yield and the 10-year treasury yield closes, investors likely will become increasingly interested in the Electric Utility Industry.

Challenging Market Conditions Remain

The recent macroeconomic environment has remained a challenge for most utility stocks. Indeed, almost all of the utilities we cover in the Electric Utility (Central) dropped in value since our March report. Notably, *Otter Tail* and *Fortis* outperformed their peers, both rising more than 5% over that interim. For the other companies, however, inflationary pressure, rising interest rates, and high commodity prices continue to negatively impact performance. Too, the rising interest rate environment remains a burden by increasing borrowing costs, which is especially significant for utilities as they generally have low returns on total capital and rely on heavy debt borrowings. While inflationary pressures are leading to higher operational costs and fuel prices, these companies are usually able to pass on expenses to customers, although the regulatory process can cause a lag in recovering the higher costs.

Rate relief should continue to act as a main driver of earnings growth, as the number of filings has increased. Indeed, almost all of the equities covered in the Electric Utility (Central) Industry possess subsidiaries that have recently approved or have pending rate cases. *Evergy Inc.* just filed its first rate requests in the Kansas corporation Commission in five years, on the heels of receiving approval in both of its Missouri general rate cases.

Dividends Closing The Gap On Treasury Yield

The attractive Treasury market has created competition for utilities over the past couple of months. The gap between the 10-year yield and the industrywide dividend payout has begun to narrow recently, and income-oriented investors are likely to become increasingly attracted to utilities. The interest rate environment has given income accounts an alternative for return of capital investments and as the gap closes, many will return to the Electric Utility sector.

Energy Legislation

Lawmakers are working on a deal to overhaul the U.S. permit process for energy projects as part of the debt ceiling legislation. The agreement would ease the process of building the interstate transmission lines necessary to carry clean electricity across the United States. The deal would also make changes to the National Environmental Policy Act, which requires the federal government to analyze the environmental impact of proposed actions. The deal would likely provide utilities with an improved, quicker process to carry clean electricity for energy projects, as well as help with the goal of reaching net-zero emissions by 2050.

INDUSTRY TIMELINESS: 67 (of 93)

Return On Capital VS. Return Of Capital

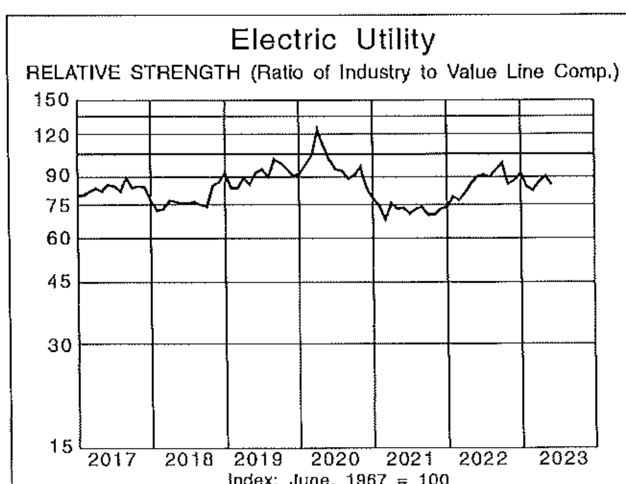
The dividend remains the most notable feature for many utilities. Indeed, the industrywide payout average of 3.6% sits well above the *Value Line* median yield of 2.4%. As the macroeconomic environment remains challenging, investors may be increasingly attracted to conservative, high-yielding investments. Note, the Federal Open Market Committee is scheduled for its next rate-setting meetings later this month. At this point, we expect conservative accounts to focus more on return of capital rather than return on capital. Also, the annual industry dividend growth projected average sits just below 5.0% and many companies remain committed to dividend hikes.

Conclusion

The industry's average dividend yield remains attractive, and is the most notable feature of utility stocks. Too, income-oriented accounts, which have increasingly entered the bond market over the past half year, are becoming more attracted to utility stocks as the gap between the average dividend yield and the 10-year Treasury yield closes.

Long-term capital appreciation potential, however, is still unattractive, and many utility stocks currently trade within our 18-month and 3-to 5-year Target Price Range. The macroeconomic environment, including inflationary pressure, rising interest rates, and high commodity energy prices are likely to remain a burden, and negatively impact results in the near-term. On the other hand, utilities are being aided by rate relief and potential legislation that will ease the process of energy projects, facilitate the transportation of electricity across the United States, and help reach the Biden Administration's goal of net-zero emissions by 2050.

Zachary J. Hodgkinson



ELECTRIC UTILITY (WEST) INDUSTRY

All major electric utilities located in the Western region of the United States are reviewed in this Issue; Eastern-based electrics, in Issue 1; and the remaining Industry participants, in Issue 5. Since our last review of this group three months ago, the 35 electric utilities we cover in *The Value Line Investment Survey* are down .6% on average, compared to the 5.6% gain in the S&P 500 for the same period. For a lengthier perspective, the group held up quite well over the course of 2022, down just 2% on average, while outperforming the S&P 500 by 17 percentage points.

Electrics have, however, experienced their share of volatility over the past several months. They seem to fair well when the market is concerned about economic weakness, as the group is viewed as something of a safe haven. Utility stocks have also been vulnerable to trepidation from rising interest rates. There was about a month-long period from mid-September to mid-October when utilities and other interest-rate sensitive issues sold off more severely than the overall market. The *Value Line Utility Index* during that stretch fell 18.5%, underperforming the S&P 500 by 550 basis points. From the October low, utilities as a group have rallied back 12%, compared to a 15% rise in the broad market.

Recent 3- to 5-year total annual return prospects for electrics look a little lean as compared with what we've seen for much of the past year. The median level for the 35 electrics we cover is presently 8.3%. Although there is a generally reduced risk level in owning utilities, given that they're regulated monopolies, we'd still like to see roughly 10%-11% long-term total annual return potential to be comfortable in recommending a specific equity to utility investors. That level is roughly in line with long-term returns for the broader market. Meanwhile, the median dividend yield for electrics is 3.6% at present, 130 basis points above the average of all dividend-paying issues covered by *Value Line*.

Utility Portfolio Considerations

We pointed out the aforementioned period of relative weakness because our biggest concern with owning utilities over the long run is how they will perform during a secular uptrend in interest rates. As a reference point, Consolidated Edison, a bellwether stock for this group, generally traded at a price-to-earnings (P/E) ratio that was roughly 55% of the market level, while carrying a dividend yield of 8%-10%, during the early to mid-1980s (the last secular peak in interest rates).

In recent years, ConEd has garnered a market level P/E ratio with a dividend yield in the 3.5%-4.0% range. And this is a very mature utility that struggles to keep up with the median growth rate of the peer group. Thus, it's clear that over time, relative valuations for utility stocks have risen with a secular decline in interest rates over the decades, and more than likely would decline significantly should rates steadily rise.

We think utility investors can help guard against sagging valuations by being disciplined buyers. The midpoint of the annual total return projections based on the 3- to 5-year Target Price Range should generally be at about 11% or greater. (A hair lower may be alright for some of the higher-growth companies.) It would also be a good practice to emphasize utilities with higher-than-average dividend growth prospects. We'd put the industry median at about 4.5%. We discussed "Dividend Growth Matters" at length in our October 21, 2022 Utility (West) report. Avoiding electrics with below-average regulatory environments is also a good practice to generally follow.

INDUSTRY TIMELINESS: 81 (of 93)

Topical Considerations And Concluding Remarks

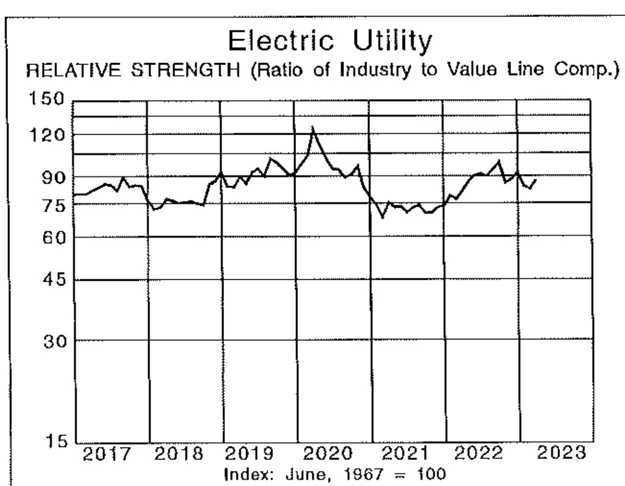
The current macroeconomic environment is a challenging period for this group. The main difficulties are wage inflation, higher interest rates, and high commodity prices for raw materials and purchased power. As a result of how the regulatory mechanisms generally work in this industry, some of these higher costs can rapidly be passed on to consumers. Still, much of the added expenses cannot be, and must instead go through a filed-rate-case process with regulators. The regulatory lag before recoupment can begin to take place may be as short as one year, but in some instances can drag on for a few years

With utility bills generally higher in recent quarters due to high energy costs, which utilities do not profit from, it can make for an antagonistic relationship with the public. Politically motivated regulatory commissioners may be reluctant to agree to raise electric and natural-gas delivery rates on behalf of utilities.

Inflationary pressures for operating and maintenance expense might be relatively manageable, but for some of the large-scale projects this industry is increasingly getting involved with (e.g., onshore and offshore wind and battery backup technologies) it will be increasingly difficult to achieve budgeted financial results. Higher financing costs is an equally challenging conundrum. The transition to a renewable-energy future has many opportunities to gain a few basis points in long-term earnings growth, but management teams will need to be up to the task in order to capitalize on them. In some instances, a poor regulatory environment will be too great a hurdle.

Although this industry appears to be homogeneous, that is far from the case. There are significant differences within this group that need to be taken account of. As always, investors need to be very selective here.

Anthony J. Glennon



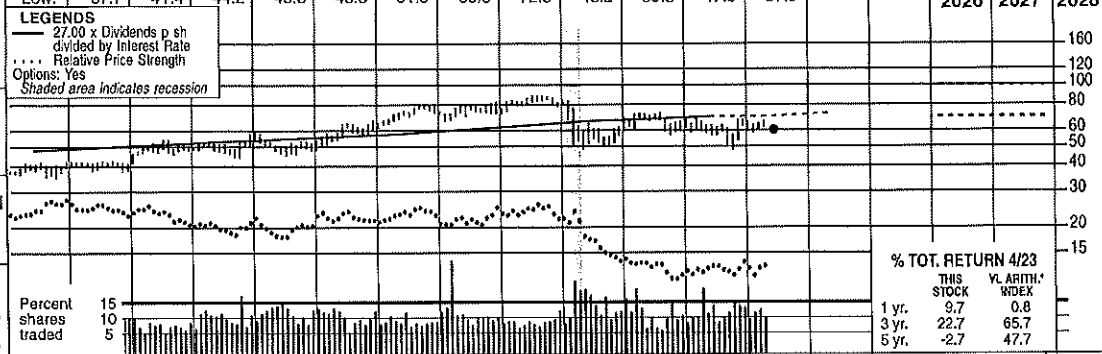
ALLETE NYSE-ALE

RECENT PRICE 60.26 | P/E RATIO 16.3 (Trailing: 18.9; Median: 19.0) | RELATIVE P/E RATIO 0.99 | DIV'D YLD 4.5% | VALUE LINE

TIMELINESS 3 Raised 5/26/23
SAFETY 2 New 10/1/04
TECHNICAL 2 Lowered 6/9/23
BETA .90 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	42.7	54.1	58.0	59.7	66.9	81.2	82.8	88.6	84.7	73.1	68.6	66.7
Low:	37.7	41.4	44.2	45.3	48.3	61.6	66.6	72.5	48.2	56.8	47.8	57.9

Target Price Range 2026 | 2027 | 2028



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$53-$89	$71 (20%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+65%)	17%
Low	70	(+15%)	8%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	172	134	153
to Sell	103	130	131
Hld's(000)	44326	44590	43870

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.7	0.8
3 yr.	22.7	65.7
5 yr.	-2.7	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	©VALUE LINE PUB. LLC	26-28
27.33	24.57	21.57	25.34	24.75	24.40	24.60	24.77	30.27	27.01	27.78	29.10	23.99	22.44	26.68	28.04	29.30	29.65	Revenues per sh	31.15
4.42	4.23	3.57	4.35	4.91	5.01	5.35	5.68	6.79	7.06	6.59	7.37	7.24	7.52	7.54	7.70	8.45	8.75	"Cash Flow" per sh	9.50
3.08	2.82	1.89	2.19	2.65	2.58	2.63	2.90	3.38	3.14	3.13	3.38	3.33	3.35	3.23	3.38	3.70	4.05	Earnings per sh A	5.00
1.64	1.72	1.76	1.76	1.78	1.84	1.90	1.96	2.02	2.08	2.14	2.24	2.35	2.47	2.52	2.60	2.71	2.79	Div'd Decl'd per sh B ■ †	3.00
6.82	9.24	9.05	6.95	6.38	10.30	7.93	12.48	5.84	5.35	4.08	6.07	11.55	13.78	8.90	3.64	5.95	5.95	Cap'l Spending per sh	7.25
24.11	25.37	26.41	27.26	28.78	30.48	32.44	35.06	37.07	38.17	40.47	41.86	43.17	44.04	45.36	47.06	49.10	51.25	Book Value per sh C	54.00
30.80	32.60	35.20	35.80	37.50	39.40	41.40	45.90	49.10	49.60	51.10	51.50	51.70	52.10	53.20	56.01	58.00	59.00	Common Shs Outst'g D	61.00
14.8	13.9	16.1	16.0	14.7	15.9	18.6	17.2	15.1	18.6	23.0	22.2	24.7	18.3	20.6	18.1	Bold figures are	Value Line	Avg Ann'l P/E Ratio	17.0
.79	.84	1.07	1.02	.92	1.01	1.05	.91	.76	.98	1.16	1.20	1.32	.94	1.11	1.05	estimates		Relative P/E Ratio	.95
3.6%	4.4%	5.8%	5.0%	4.6%	4.5%	3.9%	3.9%	4.0%	3.6%	3.0%	3.0%	2.9%	4.0%	3.8%	4.4%			Avg Ann'l Div'd Yield	3.7%

CAPITAL STRUCTURE as of 3/31/23
Total Debt $1933.3 mill. Due in 5 Yrs $390.7 mill.
LT Debt $1755.5 mill. LT Interest $65.9 mill.
(LT interest earned: 2.7x)

Leases, Uncapitalized Annual rentals $5.1 mill.

Pension Assets-12/22 $745.7 mill. Oblig $911.7 mill.

Pfd Stock None

Common Stock 57,316,155 shs.

MARKET CAP: $3.5 billion (Mid Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
1018.4	1136.8	1486.4	1339.7	1419.3	1498.6	1240.5	1169.1	1419.2	1570.7	1700	1750	Revenues ($mill)	1900
104.7	124.8	163.4	155.3	159.2	174.1	172.4	174.2	169.2	189.3	215	240	Net Profit ($mill)	305
21.5%	22.6%	19.4%	11.3%	14.8%	--	--	--	NMF	NMF	NMF	NMF	Income Tax Rate	NMF
4.4%	6.3%	2.0%	1.4%	.8%	.7%	1.3%	1.1%	1.5%	1.4%	2.0%	2.0%	AFUDC % to Net Profit	1.0%
44.6%	44.2%	46.3%	42.0%	41.0%	39.9%	38.6%	41.0%	42.2%	40.8%	39.5%	39.5%	Long-Term Debt Ratio	40.5%
55.4%	55.8%	53.7%	58.0%	59.0%	60.1%	61.4%	59.0%	57.8%	59.6%	60.5%	60.5%	Common Equity Ratio	59.5%
2425.9	2882.2	3388.9	3263.4	3507.4	3584.3	3632.8	3887.8	4176.3	4457.5	4700	4900	Total Capital ($mill)	5550
2576.5	3286.4	3669.1	3741.2	3822.4	3904.4	4377.0	4840.8	5100.2	5004.0	5300	5450	Net Plant ($mill)	5675
5.3%	5.2%	5.8%	5.8%	5.5%	5.8%	5.6%	5.3%	4.8%	5.6%	5.5%	5.5%	Return on Total Cap'l	6.0%
7.8%	7.8%	9.0%	8.2%	7.7%	8.1%	7.7%	7.6%	7.0%	7.5%	8.0%	8.0%	Return on Shr. Equity	9.0%
7.8%	7.8%	9.0%	8.2%	7.7%	8.1%	7.7%	7.6%	7.0%	7.5%	8.0%	8.0%	Return on Com Equity E	9.0%
2.2%	2.5%	3.6%	2.8%	2.4%	2.7%	2.3%	2.0%	1.5%	2.5%	2.5%	2.5%	Retained to Com Eq	3.5%
72%	67%	60%	66%	68%	66%	70%	74%	78%	76%	70%	69%	All Div'ds to Net Prof	60%

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-12.0	+11.5	+4.7
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) F	1588	1557	1556
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	230	219	220

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	--	-3.0%	3.0%
"Cash Flow"	4.5%	2.0%	4.5%
Earnings	3.0%	.5%	6.0%
Dividends	3.5%	3.5%	3.5%
Book Value	4.5%	3.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2020	311.6	243.2	293.9	320.4	1169.1
2021	339.2	335.6	345.4	399.0	1419.2
2022	383.5	373.1	388.3	425.8	1570.7
2023	564.9	395	400	340.1	1700
2024	425	420	445	460	1750

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2020	1.28	.39	.78	.90	3.35
2021	.99	.53	.53	1.18	3.23
2022	1.24	.67	.59	.90	3.38
2023	1.02	.83	.80	1.05	3.70
2024	1.35	.65	.90	1.15	4.05

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.5875	.5875	.5875	.5875	2.35
2020	.6175	.6175	.6175	.6175	2.47
2021	.63	.63	.63	.63	2.52
2022	.65	.65	.65	.65	2.60
2023	.6775	.6775			

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, 26%; paper/wood products, 9%; other industrial, 8%; residential, 13%; commercial, 13%; wholesale, 14%; other, 16%. ALLETE Clean Energy (ACE) owns renewable energy projects. Acq'd U.S. Water Services 2/15; sold it 3/19. Generating sources: coal, 28%; wind, 10%; other, 4%; purchased, 58%. Fuel costs: 40% of revs. '22 deprec. rate: 3.2%. Has 1,400 employees. Chairman, President & CEO: Bethany M. Owen. Inc.: Minnesota. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE remains focused on the development of clean and renewable energy projects, including the company's carbon-reduction goals. As a result, Allete Clean Energy recently completed the sale of its 92-megawatt Red Barn wind facility in Wisconsin to *WEC Energy Group* utility Wisconsin Public Service corp. and Madison Gas and Electric Co. Still, ALLETE Clean Energy recorded first quarter net income of $8.5 million compared to $16.5 million last year. Higher operating and maintenance expenses, along with lower wind resources and availability led to the decline. On a positive note, investments in renewable energy facilities, New Energy, and BNI Energy posted income of $9.1 million, versus a net loss of $1.7 million in 2022.

We continue to expect solid earnings growth this year. Interim rates at Minnesota Power and the sale of the Red Barn Project should act as the main drivers towards performance in 2023, despite the continued challenging operating environment. Our bottom-line projection remains at the midpoint of management's full-year updated earnings per share range of $3.55 to $3.85. The utility also expects New Energy to provide full year earnings of $16 million-$17 million.

We look for earnings of $4.05 a share in 2024, in line with the company's annual profit growth rate goal of 5%-7%. The utility should continue to benefit from rate relief and tax credits that provide investment options, as well as the sale of transfer projects and strong performances from the regulated operations segment moving forward. Too, the macroeconomic environment, including higher operating and maintenance costs, and lower wind resources will likely improve over that interim.

These shares may appeal to income-oriented investors. The utility carries a dividend yield of 4.5%, which is above the industry average. The stock also holds high scores for Price Stability and Earnings Predictability, and are ranked 2 (Above Average) for Safety. While 18-month and 3-to 5-year capital appreciation potential does not stand out, total return prospects are superior to that of most utility issues.

Zachary J. Hodgkinson *June 9, 2023*

(A) Diluted EPS. Excl. nonrec. gains (loss): '15, (46¢); '17, 25¢; '19, 26¢; '19 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. deferred charges. In '22: $9.60/sh. (D) In mill. (E) Rate base: Orig. cost depr. Rate all'd in MN on com. eq. in '18: 9.25%; earned on avg. com. eq., '21: 7.2%. Regul. Climate: Avg. (F) Summer peak in '21.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	35
Earnings Predictability	90

ALLIANT ENERGY NDQ-LNT

RECENT PRICE 50.97 | P/E RATIO 17.9 (Trailing: 19.5; Median: 21.0) | RELATIVE P/E RATIO 1.09 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 4 Lowered 3/24/23
SAFETY 2 Raised 9/28/07
TECHNICAL 3 Raised 6/2/23
BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$46-$77	$62 (20%)

2026-28 PROJECTIONS

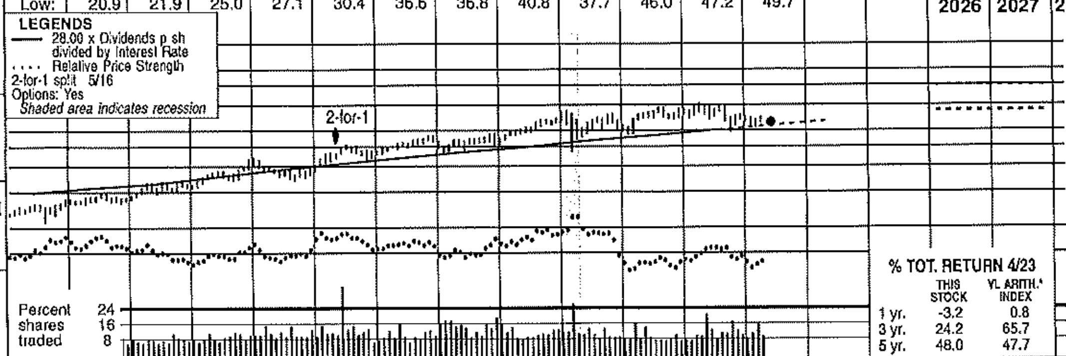
	Price	Gain	Ann'l Total Return
High	80	(+55%)	15%
Low	60	(+20%)	8%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	314	278	329
to Sell	232	263	252
Hld's(000)	188290	192005	192231

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	23.8	27.1	34.9	35.4	41.0	45.6	46.6	55.4	60.3	62.3	65.4	56.3
Low:	20.9	21.9	25.0	27.1	30.4	36.6	36.8	40.8	37.7	46.0	47.2	49.7

Target Price Range 2026 | 2027 | 2028



% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-3.2	0.8
3 yr.	24.2	65.7
5 yr.	48.0	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
15.57	16.67	15.51	15.40	16.51	13.94	14.77	15.10	14.34	14.58	14.62	14.97	14.89	13.67	14.65	16.74	16.50	16.55	Revenues per sh	16.95
2.56	2.28	2.10	2.60	2.75	2.95	3.34	3.49	3.45	3.43	3.97	4.32	4.59	4.92	5.25	5.40	5.50	5.75	"Cash Flow" per sh	6.45
1.35	1.27	.95	1.38	1.38	1.53	1.65	1.74	1.69	1.65	1.99	2.19	2.33	2.47	2.63	2.73	2.85	3.10	Earnings per sh A	3.80
.64	.70	.75	.79	.85	.90	.94	1.02	1.10	1.18	1.26	1.34	1.42	1.52	1.61	1.71	1.81	1.92	Div'd Decl'd per sh B ■ †	2.29
2.46	3.98	5.43	3.91	3.03	5.22	3.32	3.78	4.25	5.26	6.34	6.92	6.69	5.47	4.67	5.91	5.80	5.80	Cap'l Spending per sh	5.40
12.15	12.78	12.54	13.05	13.57	14.12	14.79	15.54	16.41	16.96	18.08	19.43	21.24	22.76	23.91	24.99	26.55	27.80	Book Value per sh C	31.90
220.72	220.90	221.31	221.79	222.04	221.97	221.89	221.87	226.92	227.67	231.35	236.06	245.02	249.87	250.47	251.14	255.80	256.00	Common Shs Outst'g D	257.00
15.1	13.4	13.9	12.5	14.5	14.5	15.3	16.6	18.1	22.3	20.6	19.1	21.2	21.2	21.2	21.4	Bold figures are		Avg Ann'l P/E Ratio	18.0
.80	.81	.93	.80	.91	.92	.86	.87	.91	1.17	1.04	1.03	1.13	1.09	1.15	1.24	Value Line		Relative P/E Ratio	1.00
3.1%	4.1%	5.7%	4.6%	4.3%	4.1%	3.7%	3.5%	3.6%	3.2%	3.1%	3.2%	2.9%	2.9%	2.9%	2.9%	estimates		Avg Ann'l Div'd Yield	3.7%
						3276.8	3350.3	3253.6	3320.0	3382.2	3534.5	3647.7	3416.0	3669.0	4205.0	4220	4240	Revenues ($mill)	4350
						382.1	395.7	390.9	384.0	466.1	522.3	567.4	624.0	674.0	686.0	715	800	Net Profit ($mill)	975
						12.4%	10.1%	15.3%	13.4%	12.5%	8.4%	10.8%	--	10.8%	3.1%	1.0%	2.0%	Income Tax Rate	2.0%
						8.1%	8.8%	9.4%	16.3%	10.7%	14.5%	16.3%	8.8%	3.7%	8.7%	4.0%	4.0%	AFUDC % to Net Profit	4.0%
						46.1%	49.7%	47.3%	51.5%	47.8%	52.3%	50.6%	53.5%	52.9%	55.0%	53.5%	52.5%	Long-Term Debt Ratio	52.0%
						50.8%	47.5%	50.0%	46.1%	49.8%	45.7%	47.6%	44.9%	47.1%	45.0%	46.5%	47.5%	Common Equity Ratio	48.0%
						6461.0	7257.2	7446.3	8377.6	8392.8	10032	10938	12657	12725	13944	14665	15035	Total Capital ($mill)	17070
						7147.3	6442.0	8970.2	9809.9	10798	12462	13527	14336	14987	16247	17050	17090	Net Plant ($mill)	19180
						7.0%	6.5%	6.3%	5.6%	6.7%	6.3%	6.3%	5.9%	6.3%	6.1%	6.5%	6.5%	Return on Total Cap'l	7.0%
						11.0%	10.8%	10.0%	9.5%	10.6%	10.9%	10.5%	10.6%	11.3%	10.9%	10.5%	11.0%	Return on Shr. Equity	12.0%
						11.3%	11.2%	10.2%	9.7%	10.9%	11.2%	10.7%	10.8%	11.0%	10.9%	10.5%	11.0%	Return on Com Equity E	12.0%
						4.9%	4.6%	3.6%	2.8%	4.0%	4.4%	4.2%	4.2%	4.3%	4.1%	4.0%	4.5%	Retained to Com Eq	4.5%
						57%	60%	66%	72%	64%	62%	61%	62%	62%	62%	62%	62%	All Div'ds to Net Prof	60%

CAPITAL STRUCTURE as of 12/31/22
Total Debt $9050 mill. **Due in 5 Yrs** $2117 mill.
LT Debt $8132 mill. **LT Interest** $285 mill.
(LT interest earned: 3.5x)

Leases, Uncapitalized Annual rentals $3 mill.

Pension Assets-12/22 $706 mill. **Oblig** $875 mill.

Pfd Stock None

Common Stock 251,387,788 shs.

MARKET CAP: $12.8 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-2.3	+3.7	-.7
Avg. Indust. Use (MWH)	11134	11696	11494
Avg. Indust. Revs. per KWH (¢)	7.55	7.64	8.39
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	5496	5486	5629
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.8	+.7
Fixed Charge Cov. (%)	251	259	NA

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	--	.5%	2.0%
"Cash Flow"	6.5%	7.5%	3.5%
Earnings	6.0%	8.0%	6.5%
Dividends	6.5%	6.5%	6.0%
Book Value	6.0%	7.0%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	916	763	920	817	3416
2021	901	817	1024	927	3669
2022	1068	943	1135	1059	4205
2023	1077	945	1140	1058	4220
2024	1080	950	1145	1065	4240

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.72	.54	.94	.26	2.47
2021	.68	.57	1.02	.35	2.63
2022	.77	.63	.90	.43	2.73
2023	.65	.63	1.05	.52	2.85
2024	.88	.72	1.02	.48	3.10

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.355	.355	.355	.355	1.42
2020	.38	.38	.38	.38	1.52
2021	.4025	.4025	.4025	.4025	1.61
2022	.4275	.4275	.4275	.4275	1.71
2023	.4525	.4525			

BUSINESS: Alliant Energy Corporation (formerly Interstate Energy) is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies electricity to 985,000 customers and gas to 425,000 customers in Wisconsin, Iowa, and Minnesota. Electric revenue by state: WI, 43%; IA, 56%. MN, 1%. Electric revenue: residential, 36%; commercial, 25%; industrial, 29%; wholesale, 8%; other, 2%. Generating sources: coal, 32%; gas, 32%; wind, 16%; other, 1%; purchased, 19%. Fuel costs: 25% of revs. '21 reported deprec. rates: 2.9%-6.1%. Has 3,300 employees. Chairman, President & CEO: John O. Larsen. Inc.: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, Wisconsin 53718-2148. Tel.: 608-458-3311. Internet: www.alliantenergy.com.

We have lowered our 2023 share-earnings estimate for Alliant Energy by a nickel. At $2.85, our new call represents an increase of 4.4% over the $2.73 that the Wisconsin-based electric and gas utility tallied last year. Key assumptions include revenues of $4.22 billion (up less than 1%, year over year) and modest expansion in the net profit margin. **Our less-positive near-term stance partly reflects increased concern about residential power use, amid fairly mild weather across Alliant's service area.** To that point, as measured by heating degree days, the weather in the key Madison, Wisconsin metro area has been 10% milder than normal through the first few months of 2023. Meantime, Cedar Rapids, Iowa has also enjoyed unseasonably balmy temperatures, which has likely continued to limit power-consuming heating and cooling demand.

We look for earnings to reach $3.80 a share by 2026–2028. Our target implies average annual profit growth of 6%–9% over the next 4 to 6 years. Underpinning our positive stance is an expanded rate base, as well as generally favorable demographics across Alliant's three-state service area. Operating and maintenance costs should also trend lower, as the utility, for example, transitions to fewer overhead distribution lines in favor of underground assets that are less susceptible to weather damage.

The utility's investment roadmap includes a notable amount of energy storage. Late last year, Alliant filed a plan with the Public Service Commission of Wisconsin, calling for the addition of 175 megawatts of battery storage in the state. Specifically, the facilities would be located in Grant and Wood counties, alongside two previously-approved solar arrays. Importantly, they'd provide bridge power for more than 180,000 homes at times when sun- and wind-power generation is inadequate.

Shares of Alliant Energy are ranked 4 (Below Average) for relative year-ahead price performance. Still, over the next several years, we think LNT shares may outperform many of its peers', compensating investors for a dividend yield slightly below the industry average.

Nils C. Van Liew *June 9, 2023*

(A) Diluted EPS. Excl. nonrecurring losses: '11, 1¢; '12, 8¢. '20 & '21 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Dividends historically paid in mid-Feb., May, Aug., and Nov. ■ Dividend reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '21: $1,980 mill., $7.91/sh. (D) In millions, adj. for split. (E) Rate base: Orig. cost. Rates all'd on com. eq. in IA in '20: various; in WI in '22: 10%; earned on avg. com. eq., '21: 11.3%. Regulatory Climate: Wisconsin, Above Average; Iowa, Average.

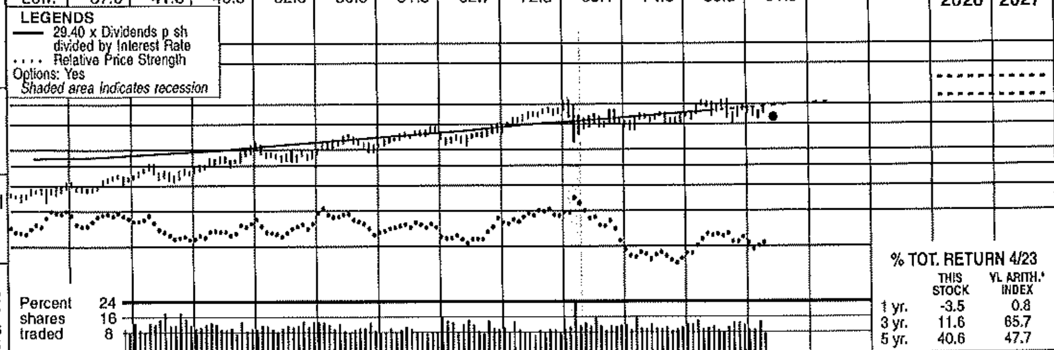
Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	95

AMERICAN ELEC. PWR. NDQ-AEP

RECENT PRICE 82.25 | P/E RATIO 15.9 (Trailing: 21.3 / Median: 17.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 3 Raised 4/28/23
SAFETY 1 Raised 3/17/17
TECHNICAL 3 Raised 5/26/23
BETA .75 (1.00 = Market)

High:	45.4	51.6	63.2	65.4	71.3	78.1	81.1	96.2	105.0	91.5	105.6	98.3	
Low:	37.0	41.8	45.8	52.3	56.8	61.8	62.7	72.3	65.1	74.8	80.3	81.3	



Target Price Range 2026 | 2027 | 2028

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$75-$123 $99 (20%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	135	(+65%)	16%
Low	110	(+35%)	11%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	634	624	707
to Sell	521	499	496
Hld's(000)	385400	384675	390225

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-3.5	0.8
3 yr.	11.6	65.7
5 yr.	40.6	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
33.41	35.56	28.22	30.01	31.27	30.77	31.48	34.78	33.51	33.31	31.35	32.84	31.49	30.04	33.30	38.20	*36.70*	*37.15*	Revenues per sh	*40.00*
6.80	6.84	6.32	6.29	6.83	6.92	7.02	7.57	7.98	8.47	7.95	8.77	9.35	10.28	10.98	10.72	*11.00*	*11.65*	"Cash Flow" per sh	*14.75*
2.86	2.99	2.97	2.60	3.13	2.98	3.18	3.34	3.59	4.23	3.62	3.90	4.08	4.42	4.96	5.09	*5.35*	*5.60*	Earnings per sh A	*6.80*
1.58	1.64	1.64	1.71	1.85	1.88	1.95	2.03	2.15	2.27	2.39	2.53	2.71	2.84	3.00	3.17	*3.35*	*3.52*	Div'd Decl'd per sh B ■ †	*4.16*
8.88	9.83	6.19	5.07	5.74	6.45	7.75	8.68	9.37	9.98	11.79	12.89	12.43	12.72	11.43	13.18	*15.35*	*14.15*	Cap'l Spending per sh	*14.00*
25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.37	36.44	35.38	37.17	38.58	39.73	41.38	44.49	46.60	*52.60*	*55.05*	Book Value per sh C	*62.55*
400.43	406.07	478.05	480.81	483.42	485.67	487.78	489.40	491.05	491.71	492.01	493.25	494.17	496.60	504.21	513.87	*523.00*	*530.00*	Common Shs Outst'g D	*550.00*
16.3	13.1	10.0	13.4	11.9	13.8	14.5	15.9	15.8	15.2	19.3	18.0	21.4	19.6	17.1	21.1	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.87	.79	.67	.85	.75	.88	.81	.84	.80	.80	.97	.97	1.14	1.01	.92	1.23	*Value Line*		Relative P/E Ratio	*1.00*
3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	3.8%	3.5%	3.4%	3.6%	3.1%	3.3%	3.5%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 3/31/23
Total Debt $42766 mill. Due in 5 Yrs $12886 mill.
LT Debt $39144 mill. LT Interest $1400 mill.

Leases, Uncapitalized Annual rentals $119.6 mill.

Pfd Stock None

Common Stock 513,866,081 shs.

MARKET CAP: $42.3 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
15357	17020	16453	16380	15425	16196	15561	14919	16792	19640	*19200*	*19700*	Revenues ($mill)	*22000*
1549.0	1634.0	1763.4	2073.6	1783.2	1923.8	2019.0	2200.1	2488.1	2307.2	*2765*	*2990*	Net Profit ($mill)	*3740*
36.2%	37.8%	35.1%	26.8%	33.7%	5.8%	.7%	1.9%	4.6%	NMF	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
7.3%	9.0%	11.0%	8.0%	8.0%	10.7%	12.7%	9.7%	7.8%	7.0%	*7.0%*	*7.0%*	AFUDC % to Net Profit	*5.0%*
51.1%	49.0%	49.8%	50.0%	51.5%	53.2%	56.1%	58.5%	58.3%	58.5%	*58.0%*	*58.0%*	Long-Term Debt Ratio	*57.5%*
48.9%	51.0%	50.2%	50.0%	48.5%	46.8%	43.9%	41.5%	41.7%	42.0%	*42.0%*	*42.0%*	Common Equity Ratio	*42.5%*
32913	33001	35633	34775	37707	40677	44759	49537	53734	57520	*62950*	*68900*	Total Capital ($mill)	*75900*
40997	44117	46133	45639	50262	55099	60138	63902	66001	71283	*74600*	*78000*	Net Plant ($mill)	*87300*
6.0%	6.3%	6.1%	7.2%	5.9%	5.9%	5.6%	5.6%	5.6%	4.0%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.0%*
9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	9.7%	*10.0%*	*10.0%*	Return on Shr. Equity	*11.0%*
9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	9.7%	*10.0%*	*10.0%*	Return on Com Equity	*11.0%*
3.7%	3.8%	3.9%	5.5%	3.2%	3.5%	3.4%	3.8%	4.3%	2.9%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
62%	61%	60%	54%	67%	65%	67%	65%	61%	70%	*63%*	*63%*	All Div'ds to Net Prof	*61%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.2	- -	+3.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+1.0	NA
Fixed Charge Cov. (%)	234	243	272

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	.5%	-.5%	*3.5%*
"Cash Flow"	5.0%	5.5%	*5.5%*
Earnings	5.0%	4.0%	*6.0%*
Dividends	5.0%	5.0%	*5.5%*
Book Value	3.5%	3.5%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	3747	3494	4066	3610	14918
2021	4281	3826	4623	4061	16792
2022	4593	4640	5526	4881	19640
2023	4690	*4700*	*5350*	*4460*	*19200*
2024	*4820*	*4750*	*5375*	*4755*	*19700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	1.00	1.05	1.50	.87	4.42
2021	1.15	1.15	1.59	1.07	4.96
2022	1.22	1.20	1.62	1.05	5.09
2023	1.11	*1.25*	*1.75*	*1.24*	*5.35*
2024	*1.45*	*1.30*	*1.80*	*1.05*	*5.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.67	.67	.67	.70	2.71
2020	.70	.70	.70	.74	2.84
2021	.74	.74	.74	.78	3.00
2022	.78	.78	.78	.83	3.17
2023	.83	.83			

BUSINESS: American Electric Power Company Inc. (AEP), through 10 operating utilities, serves 5.5 million customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Has a transmission subsidiary. Electric revenue breakdown: residential, 43%; commercial, 23%; industrial, 18%; wholesale, 10%; other, 6%. Sold commercial barge operation in '15. Generating sources not available. Fuel costs: 33% of revenues. '22 reported depreciation rates (utility): 2.6%-12.5%. Has 16,700 employees. President & Chief Executive Officer: Julie Sloat. Executive Chairman: Nicholas K. Akins. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

American Electric Power is meeting expectations. First-quarter earnings per share came in at $1.11, on par with Wall Street's expectations but lower than last year's tally due to historically mild weather that restricted results. This, along with an increase in operations and maintenance costs and higher taxes, offset the benefits derived from rate increases, load growth, and more transmission revenue. Despite these challenges, effective cost management enabled management to maintain its 2023 bottom-line outlook of $5.19 to $5.39 and a long-term annual earnings growth target of 6-7%.

The company is aggressively managing its asset portfolio. It scrapped the potential sale of its Kentucky operations citing unattractive deal economics and an adverse regulatory environment as main causes. The unit, which recorded an underwhelming 2.9% return on equity over the past year, will be revamped with a focus on reliability and cost control. Also, new base rates will be effective from January 2024 onward. A recently announced sale of certain solar assets are expected to close by the end of 2023. Furthermore, AEP intends to divest its retail and distributed resources businesses, with the sale process to start this summer and completion expected in the first half of 2024. These assets collectively contribute around $650 million to annual revenue.

The company is trying to get greener. Approximately 43% of AEP's 24,600 total megawatt capacity is currently fueled by coal, which is relatively bad for the environment compared to other natural resources, and a focal point of regulators and ESG investors. AEP's four-year, $40 billion capital expenditure plan will be used to add around 17 gigawatts of cleaner power generation capacity over the next nine years. The ultimate goal is to reach "net zero" emissions by 2045, meaning balance between the amount of greenhouse gases produced and the amount removed from the atmosphere or offset elsewhere. Continued focus on debt reduction should also help the stock's valuation ahead, allowing American to become more in-line with premium-priced peers.

Risk-averse investors may want to take a closer look here.

Kevin Downing *June 9, 2023*

(A) Diluted EPS. Excl. nonrec. gains (losses): '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); '16, ($2.99); '17, 26¢; '19, (20¢); gains (loss) from disc. ops.: '06, 2¢; '08, 3¢; '15, 58¢; '16, (1¢); '22, (58¢); '23, (34¢). Next earnings report due late July. (B) Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '22: $52.5 million (D) In mill.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	95

AMEREN NYSE-AEE

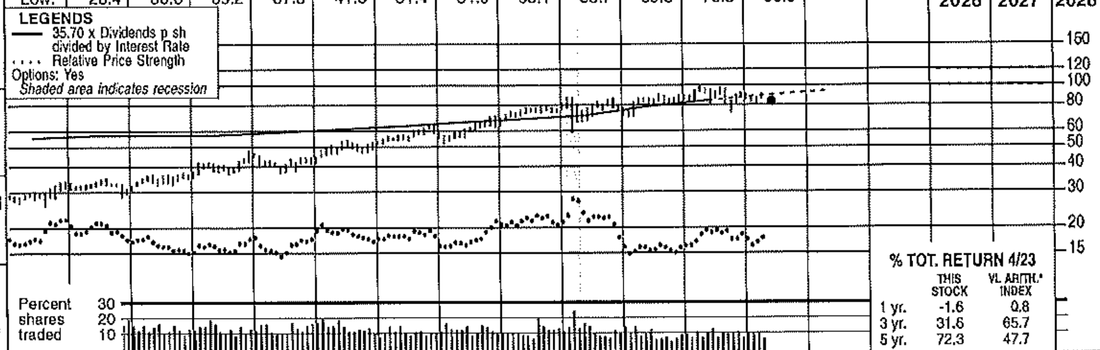
RECENT PRICE 80.77 | P/E RATIO 18.6 (Trailing: 19.4 Median: 19.0) | RELATIVE P/E RATIO 1.13 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 3 Raised 3/3/23
SAFETY 1 Raised 9/10/21
TECHNICAL 2 Raised 6/9/23
BETA .85 (1.00 = Market)

High:	35.3	37.3	48.1	46.8	54.1	64.9	70.9	80.9	87.7	90.8	99.2	91.2	
Low:	28.4	30.6	35.2	37.3	41.5	51.4	51.9	63.1	58.7	69.8	73.3	80.0	

Target Price Range 2026 | 2027 | 2028

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



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$72-$123 $98 (20%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	120	(+50%)	13%
Low	100	(+25%)	9%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	305	287	326
to Sell	257	274	270
Hld's(000)	201631	204282	206602

Percent shares traded 30 20 10

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.6	0.8
3 yr.	31.6	65.7
5 yr.	72.3	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
36.23	36.92	29.87	31.77	31.04	28.14	24.06	24.95	25.13	25.04	25.46	25.73	24.00	22.87	24.81	30.37	28.09	29.00	Revenues per sh	31.20
6.76	6.44	6.06	6.33	5.87	5.87	5.25	5.77	6.08	6.59	6.80	7.64	7.83	8.08	8.89	9.04	9.50	10.05	"Cash Flow" per sh	12.20
2.98	2.88	2.78	2.77	2.47	2.41	2.10	2.40	2.38	2.68	2.77	3.32	3.35	3.50	3.84	4.14	4.35	4.75	Earnings per sh A	5.50
2.54	2.54	1.54	1.54	1.56	1.60	1.60	1.61	1.66	1.72	1.78	1.85	1.92	2.00	2.20	2.36	2.52	2.65	Div'd Decl'd per sh B ■	3.30
6.96	9.75	7.51	4.66	4.50	5.49	5.87	7.66	8.12	8.78	9.05	9.56	9.92	13.02	13.67	12.79	12.90	12.55	Cap'l Spending per sh	13.00
32.41	32.80	33.08	32.15	32.64	27.27	26.97	27.67	28.63	29.27	29.61	31.21	32.73	35.29	37.64	40.11	40.20	42.90	Book Value per sh C	55.00
208.30	212.30	237.40	240.40	242.60	242.63	242.63	242.63	242.63	242.63	242.63	244.50	246.20	253.30	257.70	262.00	267.00	269.00	Common Shs Outst'g D	285.00
17.4	14.2	9.3	9.7	11.9	13.4	16.5	16.7	17.5	18.3	20.6	18.3	22.1	22.2	21.4	21.5	Bold figures are		Avg Ann'l P/E Ratio	20.0
.92	.85	.62	.62	.75	.85	.93	.88	.88	.96	1.04	.99	1.18	1.14	1.16	1.25	Value Line		Relative P/E Ratio	1.10
4.9%	6.2%	6.0%	5.8%	5.3%	5.0%	4.6%	4.0%	4.0%	3.5%	3.1%	3.0%	2.6%	2.6%	2.7%	2.7%	estimates		Avg Ann'l Div'd Yield	3.0%

CAPITAL STRUCTURE as of 3/31/23
Total Debt $15095 mill. Due in 5 Yrs $2789 mill.
LT Debt $13685 mill. LT Interest $450 mill.
(LT interest earned: 3.8x)
Pension Assets-12/21 $5745 mill. Oblig $5457 mill.
Pfd Stock $129 mill. Pfd Div'd $5 mill.
807,595 sh. $3.50 to $5.50 cum. (no par), $100 stated val., redeem. $102.176-$110/sh.; 487,508 sh. 4.00% to 5.16%, $100 par, redeem. $100-$104.30/sh.
Common Stock 262,609,472 shs. as of 4/28/23
MARKET CAP: $21.2 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
5838.0	6053.0	6098.0	6076.0	6177.0	6291.0	5910.0	5794.0	6394.0	7957.0	8100	8400	Revenues ($mill)	8400
518.0	593.0	585.0	659.0	683.0	821.0	834.0	877.0	995.0	1079.0	1190	1275	Net Profit ($mill)	1570
37.5%	38.9%	38.3%	36.7%	38.2%	22.4%	17.9%	15.0%	13.6%	12.0%	12.0%	12.0%	Income Tax Rate	12.0%
7.1%	5.7%	5.1%	4.1%	5.6%	6.9%	5.8%	5.5%	6.0%	5.0%	6.0%	5.0%	AFUDC % to Net Profit	4.0%
45.2%	47.2%	49.3%	47.7%	49.2%	50.3%	52.1%	55.0%	56.1%	56.6%	55.5%	53.5%	Long-Term Debt Ratio	51.0%
53.7%	51.7%	49.7%	51.3%	49.8%	48.8%	47.1%	44.3%	43.3%	44.0%	44.0%	46.0%	Common Equity Ratio	48.5%
12190	12975	13968	13840	14420	15632	17116	20158	22391	24193	24950	25750	Total Capital ($mill)	29500
16205	17424	18799	20113	21466	22810	24376	26807	29261	31262	33050	35000	Net Plant ($mill)	38400
5.6%	5.8%	5.3%	6.0%	6.0%	6.4%	6.0%	5.3%	5.3%	4.5%	5.0%	5.0%	Return on Total Cap'l	6.0%
7.7%	8.7%	8.3%	9.1%	9.3%	10.6%	10.2%	9.7%	10.1%	10.3%	11.0%	11.0%	Return on Shr. Equity	10.0%
7.8%	8.7%	8.3%	9.2%	9.4%	10.7%	10.3%	9.7%	10.2%	10.4%	11.0%	11.0%	Return on Com Equity E	10.0%
1.9%	2.9%	2.5%	3.3%	3.4%	4.8%	4.4%	4.2%	4.4%	4.4%	5.0%	5.0%	Retained to Com Eq	4.0%
76%	67%	70%	64%	64%	56%	57%	57%	57%	57%	57%	56%	All Div'ds to Net Prof	60%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-3.5	-5.6	+2.1
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 (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	307	291	325

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-2.5%	-1.0%	4.0%
"Cash Flow"	3.5%	5.5%	5.5%
Earnings	3.5%	7.0%	6.5%
Dividends	3.0%	4.0%	6.5%
Book Value	1.5%	4.5%	6.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	1440	1398	1628	1328	5794
2021	1566	1472	1811	1545	6394
2022	1879	1726	2306	2046	7957
2023	2062	1700	2280	2058	8100
2024	2100	1770	2350	2180	8400

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.59	.98	1.47	.46	3.50
2021	.91	.80	1.65	.48	3.84
2022	.97	.80	1.74	.63	4.14
2023	1.00	.80	1.90	.65	4.35
2024	1.05	.85	2.20	.65	4.75

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.475	.475	.475	.495	1.92
2020	.495	.495	.495	.515	2.00
2021	.55	.55	.55	.55	2.20
2022	.59	.59	.59	.59	2.36
2023	.63				

BUSINESS: Ameren Corporation is a holding company formed through the merger of Union Electric and CIPSCO. Has 1.2 million electric and 127,000 gas customers in Missouri; 1.2 million electric and 813,000 gas customers in Illinois. Discontinued nonregulated power-generation operation in '13. Electric revenue breakdown: residential, 49%; commercial, 34%; industrial, 8%; other, 9%. Generating sources: coal, 73%; nuclear, 11%; hydro & other, 9%; purchased, 7%. Fuel costs: 25% of revenues. Has approximately 9,250 employees. Chairman: Warner L. Baxter. President & CEO: Martin J. Lyons, Jr. Inc.: Missouri. 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 Corporation's first-quarter 2023 results demonstrate its ability to deliver solid financial performance despite challenging weather conditions. Earnings per share of $1.00 rose from $0.97 in the year-ago period. The growth was primarily driven by increased infrastructure investments across all business segments and lower operations and maintenance costs. Reduced retail sales partially offset this, due to unseasonably warm weather. Ameren remains on track to achieve its 2023 earnings target range of $4.25 to $4.45 per share. To maintain credit ratings and a healthy balance sheet, it plans to issue $300 million of common equity by the end of the year, equal to approximately 3.2 million shares.

Progress is being made on regulatory matters. There was a constructive settlement of the Ameren Missouri Electric rate review in April. The agreement calls for a $140 million annual revenue increase subject to the approval of the Missouri Public Service Commission (MPSC). This will mean residential customer rates have increased by about 2%, compounded annually since April 2017. The regulatory framework, effective through 2028, permits Ameren Missouri to make significant infrastructure investments. Two notable solar projects, the Huck Finn Solar Project in Missouri and the Boomtown Solar Project in Illinois, were approved by the MPSC in February and April, adding to Ameren's renewable energy portfolio. The Huck Finn project will be the company's largest solar project to date, capable of powering about 40,000 homes.

There is plenty of opportunity to grow the business through further investment. Ameren reportedly has a robust investment pipeline of $48 billion over the next decade. The updated five-year growth plan predicts a 6% to 8% compound annual earnings growth rate from 2023 through 2027. This is expected to be driven by robust yearly base rate growth of 8.4%.

Ameren's stock may interest conservative investors. The strategy remains customer-centric with a focus on disciplined cost management as Ameren continues its transformation towards providing more sustainable and cleaner energy.

Kevin Downing *June 9, 2023*

(A) Diluted EPS. Excl. nonrec. gain (losses): '10, ($2.19); '11, (32¢); '12, ($6.42); '17, (63¢); gain (loss) from discontinued ops.: '13, (92¢); '15, 21¢. Next earnings report due early-August. (B) Div'ds paid late Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '21: $6.60/sh. (D) In mill. (E) Rate base: Orig. cost depr. Rate allowed on com. eq. in MO in '22: elec. & gas, none specified; in IL: electric, varies; in '21: gas, 9.67%; earned on avg. com. eq., '21: 10.6%. Regulatory Climate: MO, Average; IL, Below Average.

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

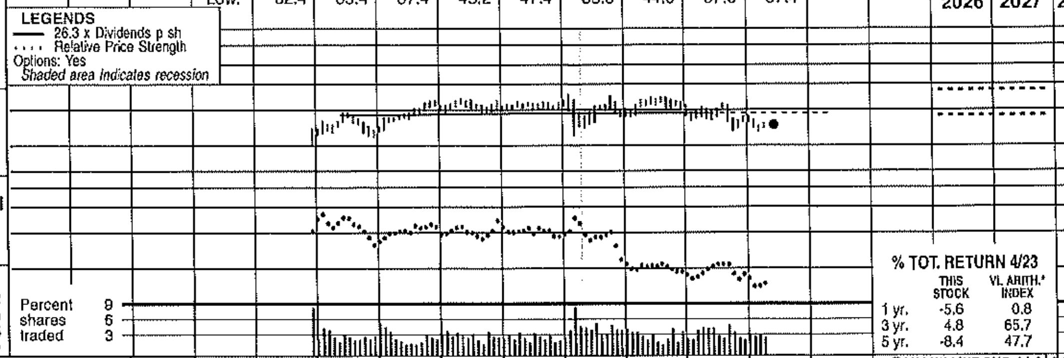
AVANGRID, INC. NYSE-AGR

RECENT PRICE 40.60 | P/E RATIO 19.3 (Trailing: 22.6 Median: NMF) | RELATIVE P/E RATIO 1.15 | DIV'D YLD 4.3% | VALUE LINE

TIMELINESS 5 Lowered 5/5/23
SAFETY 2 Raised 2/17/17
TECHNICAL 3 Raised 4/28/23
BETA .85 (1.00 = Market)

High:	38.9	46.7	53.5	54.6	52.9	57.2	55.6	51.7	44.8
Low:	32.4	35.4	37.4	45.2	47.4	35.6	44.0	37.6	37.4

Target Price Range 2026 | 2027 | 2028



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$34-$60	$47 (15%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+50%)	13%
Low	45	(+10%)	7%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	143	166	190
to Sell	133	114	125
Hld's(000)	46587	46742	48560

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-5.6	0.8
3 yr.	4.8	65.7
5 yr.	-8.4	47.7

AVANGRID, Inc. was formed through a merger between Iberdrola USA, Inc. and UIL Holdings Corporation in December of 2015. Iberdrola S.A., a worldwide leader in the energy industry, owns 81.5% of AVANGRID. The predecessor company was founded in 1852 and is headquartered in New Gloucester, Maine. It was incorporlated in 1997 in New York under the name NGE Resources, Inc. AVANGRID began trading on the NYSE on December 17, 2015.

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
--	--	14.14	19.48	19.30	20.96	20.51	20.45	18.04	20.49	*21.95*	*22.75*	Revenues per sh	*25.20*
--	--	3.44	4.74	4.49	4.89	5.41	5.22	4.64	5.14	*4.95*	*5.35*	"Cash Flow" per sh	*6.30*
--	--	1.05	1.98	1.67	1.92	2.17	2.02	2.18	2.32	*2.10*	*2.35*	Earnings per sh A	*2.75*
--	--	--	1.73	1.73	1.74	1.76	1.76	1.76	1.76	*1.76*	*1.76*	Div'd Decl'd per sh B ■	*1.94*
--	--	3.50	5.52	7.82	5.78	8.87	9.00	7.70	6.52	*8.65*	*9.00*	Cap'l Spending per sh	*9.50*
--	--	48.74	48.90	48.79	48.88	49.31	49.21	49.35	50.13	*50.50*	*51.00*	Book Value per sh C	*53.25*
--	--	308.86	308.99	309.01	309.01	309.01	309.08	386.57	386.63	*387.00*	*387.00*	Common Shs Outst'g D	*387.00*
--	--	33.5	20.5	27.3	26.1	23.1	23.6	23.2	19.6	*Bold figures are*		Avg Ann'l P/E Ratio	*18.5*
--	--	1.69	1.08	1.37	1.41	1.23	1.21	1.25	1.14	*Value Line*		Relative P/E Ratio	*1.05*
--	--	--	4.3%	3.8%	3.5%	3.5%	3.7%	3.5%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*
--	4594.0	4367.0	6018.0	5963.0	6478.0	6338.0	6320.0	6974.0	7923.0	*8500*	*8800*	Revenues ($mill)	*9750*
--	424.0	267.0	611.0	516.0	595.0	673.0	625.0	780.0	901.0	*870*	*910*	Net Profit ($mill)	*1065*
--	39.9%	11.3%	37.4%	32.4%	22.1%	17.0%	7.2%	6.2%	3.2%	*7.0%*	*7.0%*	Income Tax Rate	*7.0%*
--	6.8%	12.7%	7.5%	12.4%	9.4%	15.0%	17.1%	15.5%	12.9%	*17.0%*	*15.0%*	AFUDC % to Net Profit	*13.0%*
--	16.8%	23.1%	23.0%	25.6%	26.2%	30.6%	40.8%	29.3%	29.8%	*31.5%*	*32.0%*	Long-Term Debt Ratio	*38.5%*
--	83.2%	76.9%	77.0%	74.4%	73.8%	69.4%	59.2%	70.7%	70.2%	*68.5%*	*68.0%*	Common Equity Ratio	*61.5%*
--	14956	19583	19619	20273	20472	21953	25687	26998	27603	*28525*	*29025*	Total Capital ($mill)	*33400*
--	17099	20711	21548	22669	23459	25218	26751	28866	30994	*33225*	*35575*	Net Plant ($mill)	*42700*
--	3.7%	2.1%	3.8%	3.1%	3.5%	3.7%	3.0%	3.4%	3.9%	*3.5%*	*3.5%*	Return on Total Cap'l	*4.0%*
--	3.4%	1.8%	4.0%	3.4%	3.9%	4.4%	4.1%	4.1%	4.6%	*4.0%*	*4.5%*	Return on Shr. Equity	*5.0%*
--	3.4%	1.8%	4.0%	3.4%	3.9%	4.4%	4.1%	4.1%	4.6%	*4.0%*	*4.5%*	Return on Com Equity E	*5.0%*
--	3.4%	1.8%	1.4%	NMF	.4%	.8%	.5%	.9%	1.1%	*.5%*	*1.0%*	Retained to Com Eq	*1.5%*
--	--	--	66%	104%	90%	81%	87%	79%	76%	*84%*	*75%*	All Div'ds to Net Prof	*70%*

CAPITAL STRUCTURE as of 3/31/23
Total Debt $9949 mill. Due in 5 Yrs $3275 mill.
LT Debt $8243 mill. LT Interest $308 mill.
Incl. $87 mill. finance leases.
(Total interest coverage: 3.6x)
Leases, Uncapitalized Annual rentals $29 mill.

Pension Assets-12/22 $2151 mill.
Oblig $2451 mill.
Pfd Stock None

Common Stock 386,640,918 shs.
as of 4/25/23
MARKET CAP: $15.7 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (MWH)	-1.7	+1.8	+.7
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 (yr-end)	+.9	+.1	+1.6
Fixed Charge Cov. (%)	237	270	247

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	--	2.0%	*4.0%*
"Cash Flow"	--	3.5%	*4.0%*
Earnings	--	7.0%	*4.0%*
Dividends	--	9.0%	*1.5%*
Book Value	--	0.5%	*1.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	1789	1392	1470	1669	6320
2021	1966	1477	1598	1933	6974
2022	2133	1794	1838	2158	7923
2023	2466	*1875*	*1950*	*2209*	*8500*
2024	*2550*	*1950*	*2025*	*2275*	*8800*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.76	.32	.32	.62	2.02
2021	1.14	.35	.34	.44	2.18
2022	1.16	.46	.31	.39	2.32
2023	.64	*.50*	*.35*	*.61*	*2.10*
2024	*.73*	*.57*	*.41*	*.64*	*2.35*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.44	.44	.44	.44	1.76
2020	.44	.44	.44	.44	1.76
2021	.44	.44	.44	.44	1.76
2022	.44	.44	.44	.44	1.76
2023	.44	.44			

BUSINESS: AVANGRID, Inc. (formerly Iberdrola USA, Inc.), is a diversified energy and utility company that serves 2.3 million electric customers in New York, Connecticut, and Maine and 1 million gas customers in New York, Connecticut, Massachusetts & Maine. Has a nonregulated generating subsidiary focused on wind and solar power generation, with 9.2 GW of capacity and 1.7 GW under construction. Renewables segment accounted for about 17% of net profits for trailing 12 months. Power/fuel costs: 31% of rev. '22 reported depr. rate: 2.6%. Iberdrola owns 81.5% of stock. Employs 7,579. Board Chair: Ignacio Sanchez Galan. CEO: Pedro Azagra Blazquez. Inc.: New York. Address: 180 Marsh Hill Road, Orange, CT 06477. Tel.: 207-629-1200. Web: www.avangrid.com.

AVANGRID is off to a weak start this year in terms of the bottom line. The company was np against a difficult March-period comparison, given that last year's share earnings of $1.16 inclnded a $0.47 unusual item related to the contractual restructuring of a partnership agreement. The company still fell $0.13 a share short of our estimate, as interest and operating/maintenance expenses rose, while AVANGRID has only received rate relief thus far in 2023 from Massachusetts.

Year-over-year earnings comparisons should be on the mend later this year. AVANGRID is suffering from regulatory lag in its New York, Maine and Connecticut territories. The company's ntilities are in settlement talks with their state regulatory hoards for rate relief, and AVANGRID leadership expects to receive higher prices over the course of this year.

Conclnding the acquisition of PNM Resources is a priority. To recap, AVANGRID agreed to purchase the parent of electric utilities in New Mexico and Texas for $4.3 billion. The deal was blocked in New Mexico. The companies have recently extended their agreement to July 20th, and are back in discussions with a revamped regulatory commission, which has all new voting memhers, as former commissioners completed their terms. We expect the deal to go through. See our April 21st PNM Resources (NYSE: PNM) report for a more detailed discussion.

AVANGRID is a key player in the burgeoning "green" energy arena. Existing renewable power generation comes from onshore wind and solar. Construction of the first U.S. large-scale offshore wind project began in November 2021 and is expected to he completed by late 2024. Over time, renewahles should grow to become a larger income source for AGR. (The segment accounted for 20% of first-quarter consolidated net income.) The PNM purchase offers further avenues of expansion, providing a base of operation for solar and wind projects in the Southwest.

This issue, however, is untimely. Utility investors may find the intermediate-term total return prospects worthwhile. But, there is no rush to get involved here, as there are bound to be kinks to work out shonld the merger go through.

Anthony J. Glennon *May 12, 2023*

(A) Diluted egs. Excl. nonrecur. gain/(loss): '16, 6¢; '17, (44¢); '19, 9¢; '20, (14¢); '21, (21¢); '22, (5¢); 1Q '23, (1¢). EPS may not sum to full-year due to rounding. Next earnins report due late July. (B) Div'ds paid in early Jan., April, July, and Oct. ■ Dividend reinvestment plan available. (C) Incl. intangibles. In '22: $5,721 mill., $14.80/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on com. eq. in NY in '20: 8.8%; in CT in '17: 9.1% elec.; in CT in '19: 9.3% gas; in ME in '22: 9.25%. Regulatory Climate: Below Average.

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

AVISTA CORP. NYSE-AVA

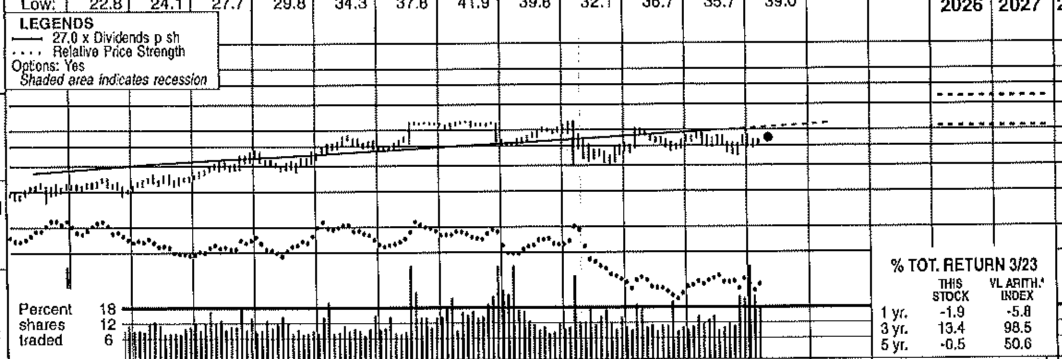
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD
44.02	17.3	(Trailing: 20.8 / Median: 19.0)	1.00	4.2%

VALUE LINE

TIMELINESS 3 Lowered 3/31/23
SAFETY 2 Raised 5/7/10
TECHNICAL 5 Lowered 4/21/23
BETA .90 (1.00 = Market)

High:	28.0	29.3	37.4	38.3	45.2	52.8	52.9	49.5	53.0	49.1	46.9	45.3
Low:	22.8	24.1	27.7	29.8	34.3	37.8	41.9	39.8	32.1	36.7	35.7	39.0

Target Price Range 2026 | 2027 | 2028



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$34-$53	$44 (0%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+60%)	15%
Low	50	(+15%)	7%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	135	138	153
to Sell	118	114	125
Hld's(000)	60878	61258	66349

Percent shares traded 18 12 6

% TOT. RETURN 3/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.9	-5.8
3 yr.	13.4	98.5
5 yr.	-0.5	50.6

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
26.80	30.77	27.58	27.29	27.73	25.86	26.94	23.66	23.83	22.47	22.08	21.27	20.03	19.09	20.13	22.82	*21.45*	*22.15*	Revenues per sh	*22.60*
2.93	3.98	4.45	3.62	3.78	3.70	4.36	4.36	4.92	5.30	4.87	5.01	6.06	5.16	5.34	4.40	*4.85*	*5.30*	"Cash Flow" per sh	*6.55*
.72	1.36	1.58	1.65	1.72	1.32	1.85	1.84	1.89	2.15	1.95	2.07	2.97	1.90	2.10	2.12	*2.30*	*2.45*	Earnings per sh A	*3.00*
.60	.69	.81	1.00	1.10	1.16	1.22	1.27	1.32	1.37	1.43	1.49	1.55	1.62	1.69	1.76	*1.84*	*1.92*	Div'd Decl'd per sh B ■	*2.15*
4.04	4.09	3.86	3.64	4.20	4.61	5.05	5.47	6.46	6.34	6.30	6.46	6.59	5.84	6.15	6.03	*6.25*	*6.30*	Cap'l Spending per sh	*6.50*
17.27	18.30	19.17	19.71	20.30	21.06	21.61	23.84	24.53	25.69	26.41	26.99	28.87	29.31	30.14	31.15	*32.55*	*34.10*	Book Value per sh C	*36.75*
52.91	54.49	54.84	57.12	58.42	59.81	60.08	62.24	62.31	64.19	65.49	65.69	67.18	69.24	71.50	74.95	*77.00*	*78.50*	Common Shs Outst'g D	*85.00*
30.9	15.0	11.4	12.7	14.1	19.3	14.6	17.3	17.6	18.8	23.4	24.5	15.0	21.2	20.2	20.0	*Bold figures are*		Avg Ann'l P/E Ratio	*20.0*
1.64	.90	.76	.81	.88	1.23	.82	.91	.89	.99	1.18	1.32	.80	1.09	1.09	1.16	*Value Line*		Relative P/E Ratio	*1.10*
2.7%	3.4%	4.5%	4.8%	4.5%	4.6%	4.5%	4.0%	4.0%	3.4%	3.1%	2.9%	3.5%	4.0%	4.0%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 12/31/22
Total Debt $2851.6 mill. Due in 5 Yrs $28.5 mill.
LT Debt $2375.1 mill. LT Interest $130.0 mill.
Incl. $51.5 mill. debt to affiliated trusts; $42.5 mill. finance leases.
(LT interest earned: 2.2x)
Leases, Uncapitalized Annual rentals $10.3 mill.
Pension Assets-12/22 $540.7 mill. Oblig $557.7 mill.
Pfd Stock None

Common Stock 75,030,135 shs. as of 1/31/23
MARKET CAP: $3.3 billion (Mid Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
1618.5	1472.6	1484.8	1442.5	1445.9	1396.9	1345.6	1321.9	1438.9	1710.2	*1650*	*1740*	Revenues ($mill)	*1920*
111.1	114.2	118.1	137.2	126.1	136.4	197.0	129.5	147.3	155.2	*175*	*190*	Net Profit ($mill)	*255*
36.0%	37.6%	36.3%	36.3%	36.5%	16.0%	13.8%	5.2%	7.5%	15.0%	*15.0%*	*15.0%*	Income Tax Rate	*15.0%*
8.8%	11.1%	10.1%	8.1%	7.9%	7.7%	5.5%	8.5%	7.5%	2.4%	*6.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
51.4%	51.0%	50.0%	51.2%	47.2%	50.5%	49.4%	50.4%	47.5%	50.4%	*50.5%*	*50.5%*	Long-Term Debt Ratio	*49.5%*
48.6%	49.0%	50.0%	48.8%	52.8%	49.5%	50.6%	49.6%	52.5%	49.6%	*49.5%*	*49.5%*	Common Equity Ratio	*50.5%*
2669.7	3027.3	3060.3	3379.0	3273.2	3580.3	3834.6	4089.8	4104.7	4709.7	*5000*	*5200*	Total Capital ($mill)	*6000*
3202.4	3620.0	3898.6	4147.5	4398.8	4648.9	4797.0	4991.6	5225.5	5444.7	*5675*	*5900*	Net Plant ($mill)	*6400*
5.4%	4.9%	5.1%	5.3%	5.0%	4.8%	6.2%	4.2%	4.7%	4.6%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
8.6%	7.7%	7.7%	8.3%	7.3%	7.7%	10.2%	6.4%	6.8%	6.6%	*7.5%*	*7.5%*	Return on Shr. Equity	*7.5%*
8.6%	7.7%	7.7%	8.3%	7.3%	7.7%	10.2%	6.4%	6.8%	6.6%	*7.5%*	*7.5%*	Return on Com Equity E	*7.5%*
2.9%	2.4%	2.3%	3.0%	1.9%	2.2%	4.9%	.9%	1.4%	1.1%	*2.0%*	*2.0%*	Retained to Com Eq	*2.0%*
66%	69%	70%	84%	73%	72%	52%	85%	80%	83%	*80%*	*78%*	All Div'ds to Net Prof	*72%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-2.4	+4.3	+3.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.38	6.41	6.62
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	1721	1889	1810
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.8	+1.4	-1.0
Fixed Charge Cov. (%)	222	216	175

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-2.5%	-2.0%	*1.5%*
"Cash Flow"	3.0%	-0.5%	*3.5%*
Earnings	2.5%	0.5%	*6.5%*
Dividends	4.5%	4.0%	*4.0%*
Book Value	4.0%	3.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	390.2	278.6	272.6	380.5	1321.9
2021	412.9	298.2	296.0	431.8	1438.9
2022	462.7	378.6	359.4	509.5	1710.2
2023	*485*	*380*	*375*	*410*	*1650*
2024	*475*	*390*	*370*	*505*	*1740*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.72	.26	.07	.85	1.90
2021	.98	.20	.20	.71	2.10
2022	.99	.16	d.08	1.05	2.12
2023	*1.10*	*.27*	*.13*	*.80*	*2.30*
2024	*1.10*	*.30*	*.15*	*.90*	*2.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.3875	.3875	.3875	.3875	1.55
2020	.405	.405	.405	.405	1.62
2021	.4225	.4225	.4225	.4225	1.69
2022	.44	.44	.44	.44	1.76
2023	.46				

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: 411,000 electric, 377,000 gas. Acq'd Alaska Electric Light and Power 7/14. Sold Ecova energy-management sub. 6/14. Electric rev. breakdown: residential, 38%; commercial, 30%; industrial, 10%; wholesale, 17%; other, 5%. Generating sources: gas & coal, 31%; hydro, 31%; purch., 38%. Fuel costs: 35% of revs. '22 reported depr. rate (Avista Utilities): 3.6%. Has 1,767 employees. Chairman: Scott L. Morris. Pres. & CEO: Dennis Vermillion. Inc.: WA. Address: 1411 E. Mission Ave., Spokane, WA 99202-2600. Tel.: 509-489-0500. Internet: www.avistacorp.com.

Avista has filed a multiyear electric and natural gas rate plan in Idaho. The proposal is a two-year rate plan with new rates going into effect for this September and the next. Also, to provide customers with some predictability in their future energy prices, a stay-out period where no new rate cases can be filed would extend until September of 2024. On the electric side of the coin, the request would boost annual revenues by $37.5 million and $13.2 million in the years involved. For the natural gas business, revenues would rise $2.8 million in 2023, with a nominal gain the following year. The plan is based on a proposed rate of return of 7.59%, with a common equity ratio of 50%, and a 10.25% return on equity. For the most part, average electric prices in Idaho have been flat since 2016, so we expect a favorable ruling on this front.

We think earnings growth in 2023 may be well above Avista's historic average. Revenues rose handsomely last year, but so too did the cost of doing business. Macroeconomic conditions were far from ideal due to the most unfavorable combination of inflation and rising interest rates. We look for some easing on the cost line to cushion AVA's profitability. Add to this, rate relief arrived with the new year in Washington, and the anticipation is that further rate plan approvals will roll in as the year wears on. All told, we think share earnings can climb to $2.30 this year, followed by a rise to $2.45 in 2024. The latter is more in line with what the average utility is apt to aim for in its annual earnings growth (5% to 7%).

The company's natural gas integrated resource plan (IRP) was filed in March. The IRP covers state regulators in Washington, Idaho, and Oregon and must be submitted every two years. It is an outline of projected future needs and a plan of action to meet them. Emissions compliance is included. Idaho has had considerably high customer growth, and that is likely to continue, so laying out a framework for service is paramount to success.

The yield for this neutrally ranked utility is greater than the industry average. The view through our longer-term windows (18 month and 3 to 5 years) is not all that appealing.

Erik M. Manning *April 21, 2023*

(A) Diluted EPS. Excl. nonrec. gain (loss): '14, 9¢; '17, (16¢); gains on discont. ops.: '14, $1.17; '15, 8¢. EPS may not sum due to rounding. Next earnings report due early May. (B) Div'ds paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (C) Incl. deferred chgs. In '22: $911.2 mill., $12.16/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in WA in '21: 9.4%; in ID in '21: 9.4%; in OR in '21: 9.4%; earned on avg. com. eq., '22: 7.1%. Regulatory Climate: WA, Below Avg.; ID, Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	75
Price Growth Persistence	40
Earnings Predictability	65

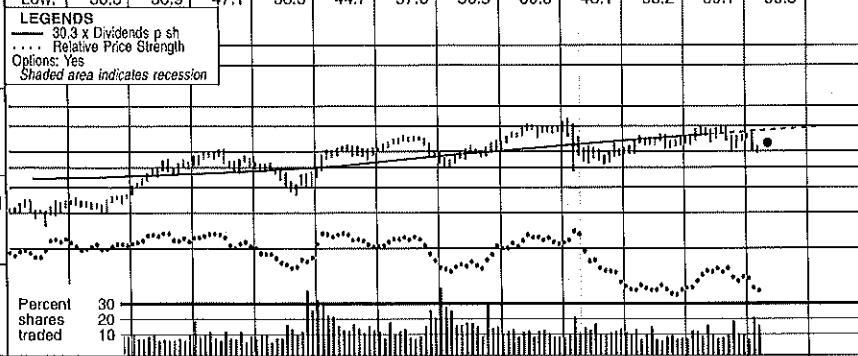
BLACK HILLS CORP. NYSE-BKH

RECENT PRICE 66.09 | P/E RATIO 17.6 (Trailing: 16.6; Median: 18.0) | RELATIVE P/E RATIO 1.02 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 4 Lowered 3/31/23
SAFETY 2 Raised 5/1/15
TECHNICAL 4 Lowered 3/31/23
BETA .95 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	37.0	55.1	62.1	53.4	64.6	72.0	68.2	82.0	87.1	72.8	80.9	74.0
Low:	30.3	36.9	47.1	36.8	44.7	57.0	50.5	60.8	48.1	58.2	59.1	58.8

Target Price Range 2026 | 2027 | 2028



% TOT. RETURN 3/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-15.2	-5.8
3 yr.	9.5	98.5
5 yr.	35.9	50.6

18-Month Target Price Range

Low-High $51-$93 | Midpoint (% to Mid) $72 (10%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+60%)	15%
Low	80	(+20%)	9%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	172	155	148
to Sell	128	142	143
Hld's(000)	57056	58257	59331

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
18.41	26.03	32.58	33.29	28.96	26.55	28.67	31.20	25.48	29.47	31.38	29.24	28.22	27.02	30.11	38.60	*34.95*	*34.00*	Revenues per sh	*35.30*
5.29	2.95	5.41	4.88	4.01	5.59	5.93	6.25	5.67	6.28	7.15	6.61	7.02	7.41	7.41	7.85	*7.65*	*7.95*	"Cash Flow" per sh	*10.00*
2.68	.18	2.32	1.66	1.01	1.97	2.61	2.89	2.83	2.63	3.38	3.47	3.53	3.73	3.74	3.97	*3.75*	*3.90*	Earnings per sh A	*5.25*
1.37	1.40	1.42	1.44	1.46	1.48	1.52	1.56	1.62	1.68	1.81	1.93	2.05	2.17	2.29	2.41	*2.53*	*2.65*	Div'd Decl'd per sh B ■	*3.07*
6.92	8.51	8.90	12.04	10.03	7.90	7.97	8.92	8.90	8.89	6.09	7.62	13.31	12.22	10.47	9.14	*9.30*	*9.35*	Cap'l Spending per sh	*9.55*
25.66	27.19	27.84	28.02	27.53	27.88	29.39	30.80	28.63	30.25	31.92	36.36	38.42	40.79	43.05	45.31	*47.35*	*49.65*	Book Value per sh C	*59.70*
37.80	38.64	38.97	39.27	43.92	44.21	44.50	44.67	51.19	53.38	53.54	60.00	61.48	62.79	64.74	66.10	*67.50*	*68.50*	Common Shs Outst'g D	*72.00*
15.0	NMF	9.9	18.1	31.1	17.1	18.2	19.0	16.1	22.3	19.5	16.8	21.2	17.0	17.7	18.1	Bold figures are		Avg Ann'l P/E Ratio	*17.5*
.80	NMF	.66	1.15	1.95	1.09	1.02	1.00	.81	1.17	.98	.91	1.13	.87	.96	1.05	Value Line		Relative P/E Ratio	*.95*
3.4%	4.2%	6.2%	4.8%	4.6%	4.4%	3.2%	2.8%	3.5%	2.9%	2.7%	3.3%	2.7%	3.4%	3.5%	3.4%	estimates		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 12/31/22
Total Debt $4667.9 mill. Due in 5 Yrs $1835.0 mill.
LT Debt $3607.3 mill. LT Interest $190.0 mill.
(LT interest earned: 3.0x)
Leases, Uncapitalized Annual rentals $2.4 mill.

Pension Assets-12/22 $323.1 mill. Oblig $358.4 mill.

Pfd Stock None

Common Stock 66,102,478 shs. as of 1/31/23

MARKET CAP: $4.4 billion (Mid Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
1275.9	1393.6	1304.6	1573.0	1680.3	1754.3	1734.9	1696.9	1949.1	2551.8	*2360*	*2330*	Revenues ($mill)	*2540*
115.8	128.8	128.3	140.3	186.5	192.5	214.5	232.9	236.7	258.4	*255*	*265*	Net Profit ($mill)	*380*
34.7%	33.7%	35.8%	25.1%	28.7%	19.2%	13.0%	12.2%	2.8%	8.5%	*8.5%*	*8.5%*	Income Tax Rate	*8.5%*
2.4%	2.4%	2.7%	5.3%	2.7%	1.4%	3.3%	2.5%	2.0%	2.0%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
51.6%	47.9%	56.0%	66.5%	64.5%	57.5%	57.1%	57.9%	59.7%	54.6%	*55.5%*	*55.5%*	Long-Term Debt Ratio	*50.0%*
48.4%	52.1%	44.0%	33.5%	35.5%	42.5%	42.9%	42.1%	40.3%	45.4%	*45.5%*	*45.5%*	Common Equity Ratio	*50.0%*
2704.7	2643.6	3332.7	4825.8	4818.4	5132.4	5502.2	6089.5	6914.0	6602.3	*6750*	*7000*	Total Capital ($mill)	*8000*
2990.3	3239.4	3259.1	4469.0	4541.4	4854.9	5503.2	6019.7	6449.2	6797.9	*7150*	*7400*	Net Plant ($mill)	*8350*
5.5%	6.1%	4.9%	4.0%	5.2%	5.0%	4.9%	5.0%	4.5%	5.0%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.5%*
8.9%	9.4%	8.8%	8.7%	10.9%	8.8%	9.1%	9.1%	8.5%	8.6%	*8.0%*	*8.5%*	Return on Shr. Equity	*9.0%*
8.9%	9.4%	8.8%	8.7%	10.9%	8.8%	9.1%	9.1%	8.5%	8.6%	*8.0%*	*8.5%*	Return on Com Equity E	*9.0%*
3.7%	4.3%	3.8%	3.3%	5.3%	3.9%	3.8%	3.8%	3.3%	3.4%	*2.5%*	*3.0%*	Retained to Com Eq	*3.0%*
58%	54%	57%	62%	52%	55%	58%	56%	61%	61%	*67%*	*68%*	All Div'ds to Net Prof	*58%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-.7	+1.5	+3.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Yearend (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	1050	1078	1107
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+1.0	+1.0
Fixed Charge Cov. (%)	285	259	281

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	1.0%	2.0%	*1.5%*
"Cash Flow"	4.5%	3.5%	*5.0%*
Earnings	9.5%	5.5%	*5.5%*
Dividends	4.5%	6.0%	*5.0%*
Book Value	4.5%	7.5%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	537.0	326.9	346.6	486.4	1696.9
2021	633.4	372.6	380.6	562.5	1949.1
2022	823.6	474.2	462.6	791.4	2551.8
2023	*745*	*475*	*465*	*675*	*2360*
2024	*740*	*465*	*455*	*670*	*2330*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	1.59	.33	.58	1.23	3.73
2021	1.54	.40	.70	1.11	3.74
2022	1.82	.52	.54	1.11	3.97
2023	*1.70*	*.40*	*.55*	*1.10*	*3.75*
2024	*1.75*	*.40*	*.60*	*1.15*	*3.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.505	.505	.505	.535	2.05
2020	.535	.535	.535	.565	2.17
2021	.565	.565	.565	.595	2.29
2022	.595	.595	.595	.625	2.41
2023	.625				

BUSINESS: Black Hills Corporation is a holding company for Black Hills Energy, which serves 220,431 electric customers in CO, SD, WY and MT, and 1.1 million gas customers in NE, IA, KS, CO, WY, and AR. Has coal mining sub. Acq'd utility ops. from Aquila 7/08; SourceGas 2/16. Discontinued gas marketing in '11; gas & oil E&P in '17. Electric rev. breakdown: residential, 35%; commercial, 39%; industrial, 23%; other, 3%. Generating sources: coal, 35%; gas, 19%; wind, 11%; purchased, 35%. Fuel costs: 38% of revs. '22 deprec. rate: 3.2%. Has 2,982 employees. Chairman: Steven R. Mills. President & CEO: Linn Evans. Inc.: SD. Address: 7001 Mount Rushmore Rd., P.O. Box 1400, Rapid City, SD 57709-1400. Telephone: 605-721-1700. Internet: www.blackhillscorp.com.

Black Hills' fourth-quarter presentation sent these shares into a tailspin. Again, we advise subscribers to look at year-over-year earnings numbers and not quarter by quarter, but this situation requires a deeper dive. Revenues soared in the period, so investors were expecting earnings to do the same. This was not the case, as EPS came in flat with the year-earlier showing due to increases up and down the cost ledger. Fuel and labor costs were cited as particular thorns in the side of profitability, with lofty interest rates also crimping the bottom line. Perhaps more damaging, management stated that cost pressures were not going anywhere in 2023. In turn, the provided earnings bracket for the current year is now $3.65 to $3.85 a share. We have placed our call at the midpoint of this range, which represents a 6% year-over-year dip. BKH stock fell as much as 15% in price on the day the numbers were released.

The company has received approval for new rates in Wyoming. The new rates went into effect as of March 1st. The approved settlement agreement will generate approximately $8.7 million of new annual revenues based on a capital structure of 52% equity, 48% debt, and a return on equity of 9.75%. On top of this, the pact includes a transmission rider that will be filed annually to recover transmission investment and expenses. The news is a boost to Black Hills' Ready Wyoming expansion project.

We are introducing an earnings target of $3.90 a share for 2024. For next year, we look for an easing of macroeconomic headwinds, especially in the latter stages of the campaign. The aforementioned figure equates to 4% earnings growth and approaches the in-house goal of 5% to 7% per annum. Upside exists to this number if cost relief comes earlier in the year than we have targeted at first blush. As for the capital plan, we look for renewables to be a focus, with 60% earmarked for gas and 40% for electric. The goal remains for net zero emissions on the gas front by 2035.

The lower quotation has propped up this untimely utility's yield. That is the primary draw at this time, as projections over the coming 18 months and stretch to 2026-2028 leave something to be desired.

Erik M. Manning *April 21, 2023*

(A) Dil. EPS. Excl. nonrec. gains (losses): '15, ($3.54); '16, ($1.26); '17, 14¢; '18, $1.31; '19, (25¢); '20, (8¢); discont. ops.: '08, $4.12; '09, 7¢; '11, 23¢; '12, (16¢); '17, (31¢); '18, (12¢). EPS may not sum due to rounding. Next egs. report due early May. (B) Dividends paid in early March, June, Sept., and Dec. ■ Div'd reinv. plan avail. (C) Incl. deferred chgs. In '22: $1748.6 mill., $26.45/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in SD in '15: none; in CO in '17: 9.37%; earn. on avg. com. eq., '21: 8.9%. Regul. Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	40
Earnings Predictability	95

CENTERPOINT EN'RGY NYSE-CNP

RECENT PRICE 28.34 | P/E RATIO 18.9 (Trailing: 22.5 Median: 19.0) | RELATIVE P/E RATIO 1.15 | DIV'D YLD 2.7% | VALUE LINE

TIMELINESS 3 Raised 5/12/23
SAFETY 3 Lowered 12/18/15
TECHNICAL 2 Lowered 6/9/23
BETA 1.10 (1.00 = Market)

High:	21.8	25.7	25.8	23.7	25.0	30.5	29.6	31.4	27.5	28.4	33.5	31.5	
Low:	18.1	19.3	21.1	16.0	16.4	24.5	24.8	24.3	11.6	19.3	25.0	27.2	

Target Price Range 2026 | 2027 | 2028

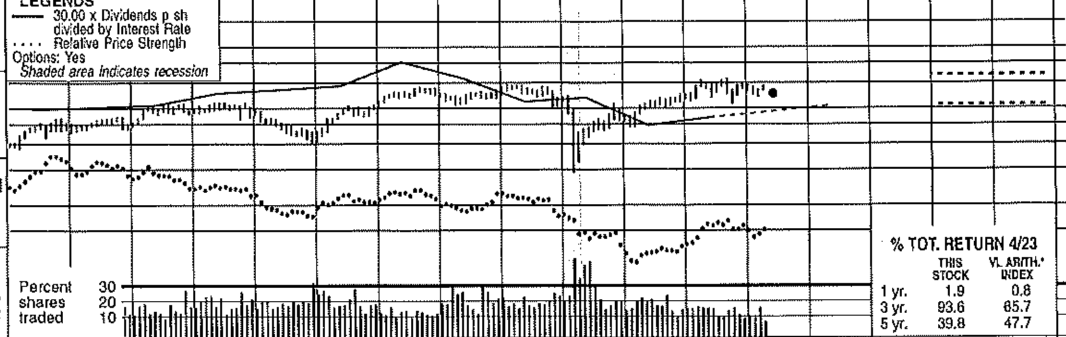
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$25-$41 $33 (15%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+25%)	8%
Low	25	(-10%)	1%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	294	256	330
to Sell	267	270	232
Hld's(000)	560317	566702	574926



% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.9	0.8
3 yr.	93.6	65.7
5 yr.	39.8	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
29.82	32.71	21.14	20.69	19.83	17.43	18.90	21.51	17.18	17.48	22.30	21.13	24.49	13.45	13.28	14.81	*14.40*	*14.80*	Revenues per sh	*16.75*
3.39	3.42	2.94	3.14	3.43	3.89	3.54	3.85	3.40	3.68	4.03	3.24	4.12	3.46	3.00	3.65	*3.80*	*4.05*	"Cash Flow" per sh	*4.75*
1.17	1.30	1.01	1.07	1.27	1.35	1.24	1.42	1.08	1.00	1.57	.74	1.49	1.29	.94	1.59	*1.65*	*1.75*	Earnings per sh A	*1.95*
.68	.73	.76	.78	.79	.81	.83	.95	.99	1.03	1.35	1.12	.86	.90	.66	.72	*.77*	*.83*	Div'd Decl'd per sh B ■	*.95*
3.45	2.95	2.96	3.55	3.06	2.84	3.00	3.20	3.68	3.28	3.31	3.29	4.99	4.71	5.03	7.02	*6.65*	*7.05*	Cap'l Spending per sh	*9.00*
5.61	5.89	6.74	7.53	9.91	10.06	10.09	10.60	8.05	8.03	10.88	12.53	13.10	10.78	13.70	14.68	*16.85*	*17.70*	Book Value per sh C	*19.50*
322.72	346.09	391.75	424.70	426.03	427.44	429.00	429.00	430.00	430.68	431.04	501.20	502.24	551.36	628.92	629.54	*631.00*	*632.00*	Common Shs Outst'g D	*634.00*
15.0	11.3	11.8	13.8	14.6	14.8	18.7	17.0	18.1	21.9	17.9	37.0	19.5	15.9	26.1	18.7	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.80	.68	.79	.88	.92	.94	1.05	.89	.91	1.15	.90	2.00	1.04	.82	1.41	1.08	*Value Line*		Relative P/E Ratio	*.90*
3.9%	5.0%	6.4%	5.3%	4.3%	4.0%	3.6%	3.9%	5.1%	4.7%	4.8%	4.1%	3.0%	4.4%	2.7%	2.4%	*estimates*		Avg Ann'l Div'd Yield	*3.2%*

CAPITAL STRUCTURE as of 3/31/23
Total Debt $15840 mill. Due in 5 Yrs $6698 mill.
LT Debt $15783 mill. LT Interest $600 mill.
Incl. $156 mill. securitized transition & system restoration bonds.
(LT interest earned: 2.4x)
Leases, Uncapitalized Annual rentals $5 mill.
Pension Assets-12/22 $1212 mill.
Oblig $1553 mill.
Pfd Stock $790 mill. **Pfd Div'd** $49 mill.
800,000 shs. 6.125%, cumulative, with liquidation value of $800.
Common Stock 631,031,243 shs. as of 4/19/23
MARKET CAP: $17.9 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
8106.0	9226.0	7386.0	7528.0	9614.0	10589	12301	7418.0	8352.0	9321.0	*9100*	*9350*	Revenues ($mill)	*10600*
536.0	611.0	465.0	432.0	679.0	368.0	871.0	863.0	668.0	1057.0	*1100*	*1160*	Net Profit ($mill)	*1285*
31.4%	31.0%	35.1%	37.0%	36.1%	28.4%	14.9%	13.4%	14.1%	25.4%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
3.5%	4.1%	4.7%	3.5%	2.9%	5.4%	6.7%	6.0%	9.3%	6.0%	*5.0%*	*5.0%*	AFUDC % to Net Profit	*5.0%*
64.4%	63.8%	69.5%	68.5%	63.6%	51.9%	63.0%	58.0%	62.3%	59.6%	*56.0%*	*55.0%*	Long-Term Debt Ratio	*53.0%*
35.6%	36.2%	30.5%	31.5%	36.4%	37.5%	29.1%	29.9%	34.5%	37.1%	*41.0%*	*42.0%*	Common Equity Ratio	*44.0%*
12146	12557	11362	10992	12883	16740	22603	19869	24973	24878	*26000*	*26500*	Total Capital ($mill)	*28000*
9593.0	10502	11537	12307	13057	14044	20945	22362	23484	27143	*30000*	*33000*	Net Plant ($mill)	*40000*
6.3%	6.7%	6.1%	5.8%	6.8%	3.4%	5.1%	5.6%	3.8%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
12.4%	13.4%	13.4%	12.5%	14.5%	4.6%	10.4%	10.3%	7.1%	10.5%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.0%*
12.4%	13.4%	13.4%	12.5%	14.5%	5.3%	11.5%	11.6%	6.7%	10.9%	*10.0%*	*10.0%*	Return on Com Equity E	*10.0%*
4.2%	4.5%	1.1%	NMF	4.7%	NMF	2.7%	5.0%	2.2%	6.1%	*5.5%*	*5.5%*	Retained to Com Eq	*5.0%*
66%	67%	92%	103%	68%	NMF	80%	66%	72%	46%	*49%*	*49%*	All Div'ds to Net Prof	*51%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	+6.7	+1.8	+2.0
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.)	+7.9	+2.5	+2.0
Fixed Charge Cov. (%)	152	135	252

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-3.5%	-6.0%	*-.5%*
"Cash Flow"	-0.5%	-2.0%	*4.0%*
Earnings	0.5%	1.0%	*6.5%*
Dividends	-0.5%	-7.5%	*2.5%*
Book Value	3.5%	8.0%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2020	2167	1575	1622	2054	7418
2021	2547	1742	1749	2314	8352
2022	2763	1944	1903	2711	9321
2023	2779	*1860*	*1900*	*2561*	*9100*
2024	*2800*	*1900*	*2050*	*2600*	*9350*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2020	.56	.17	.29	.27	1.29
2021	.41	.29	.21	.03	.94
2022	.82	.28	.30	.19	1.59
2023	.49	*.35*	*.50*	*.31*	*1.65*
2024	*.55*	*.40*	*.50*	*.30*	*1.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.2875	.2875	.2875	.2875	1.15
2020	.29	.15	.15	.15	.74
2021	.16	.16	.16	.17	.65
2022	.17	.17	.18	.18	.70
2023	.18	.19			

BUSINESS: CenterPoint Energy, Inc. is a holding company for Houston Electric, which serves 2.7 million customers in Houston and environs, Indiana Electric, which serves 151,000 customers, and gas utilities with 4.27 million customers in Texas, Minnesota, Louisiana, Mississippi, Indiana, and Ohio. Acquired Vectren 2/19. Sold nonutility operations in '20. Sold its stake in Energy Transfer LP in '21 and '22. Electric revenue breakdown not available. Fuel costs: 33% of revenues. '22 depreciation rate: 3.8%. Has 8,986 employees. Chairman: Martin H. Nesbitt. President & CEO: David J. Lesar. Incorporated: Texas. Address: 1111 Louisiana, P.O. Box 4567, Houston, Texas 77210-4567. Telephone: 713-207-1111. Internet: www.centerpointenergy.com.

CenterPoint Energy's first-quarter results were nothing to write home about. Revenues registered at $2.78 billion. Meanwhile, GAAP share earnings clocked in at $0.49, versus $0.82 in the year-ago period (including the gains on the sale of the Energy Transfer common and preferred units and impacts associated with the Arkansas and Oklahoma natural gas LDC sale). On an adjusted basis, per-share earnings increased 6% over the previous-year tally, to $0.50.

Near-term earnings are expected to stay healthy thanks to solid growth in demand. Also, ongoing rate-relief efforts and higher volumes ought to help. Hence, we estimate 2023 and 2024 share earnings each will advance at a single-digit pace.

The company is successfully following through on its $43 billion capital plan. The long-term endeavor is now in its third year. Over the past two years, CenterPoint has already invested over $8 billion in capital. By the end of the first quarter, an additional $3.6 billion was deployed. The company plans to recoup roughly 80% of the total spent amount by 2030. CenterPoint anticipates that it will not need to issue common equity through 2030, although the share count might rise slightly due to stock issued for options and various other plans.

The utility company is shifting away from using coal to generate electricity. This move is projected to save customers around $80 million and decrease carbon emissions from the electric generation fleet by over 95% in the next 20 years. Currently, about 85% of the electricity provided to customers in southwest Indiana by CenterPoint is generated from coal. However, the company plans to switch to using mainly solar and wind power to generate electricity by the year 2030.

The board of directors boosted the dividend in the second quarter. The increase was $0.01 a share (5.6%) sequentially, bringing the quarterly dividend amount to $0.19 per share. Still, the dividend yield is below the utility average.

Shares of CenterPoint have subpar near- to intermediate-term capital appreciation potential. All told, there are more attractive selections available elsewhere.

Emma Jalees *June 9, 2023*

(A) GAAP Dil. EPS 2022 & onwards. Excl. nonrecur. gains (losses): '11, $1.89; '12, (38¢); '13, (52¢); '15, ($2.69); '17, $2.56; '20, ($2.74); gain (loss) on disc. ops.: '20, (34¢); '21, $1.34. Next egs. report due early Aug. (B) Div'ds histor. paid in early Mar., June, Sept. & Dec. 5 declarations in '17 & '20, 3 in '19. ■ Div'd reinv. plan avail. (C) Incl. intang. In '22: $6.82/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. (elec.) in '20: 9.4%; (gas): 9.45%-11.25%; earned on avg. com. eq., '22: 8.27%. Regulatory Climate: TX, Avg.; IN, Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	75
Price Growth Persistence	30
Earnings Predictability	55

CMS ENERGY CORP. NYSE-CMS

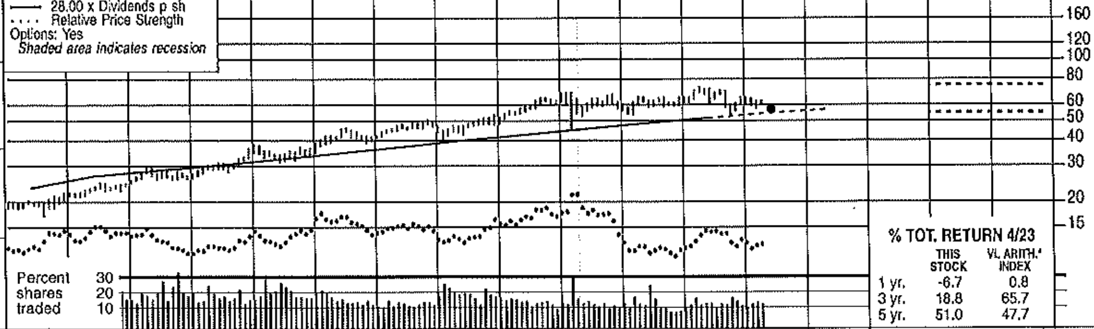
RECENT PRICE 57.10 | P/E RATIO 18.7 (Trailing: 24.5; Median: 21.0) | RELATIVE P/E RATIO 1.14 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 4 Lowered 3/31/23
SAFETY 2 Raised 3/21/14
TECHNICAL 3 Raised 5/26/23
BETA .80 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	25.0	30.0	36.9	38.7	46.3	50.6	53.8	65.3	69.2	65.8	73.8	65.7
Low:	21.1	24.6	26.0	31.2	35.0	41.1	40.5	48.0	46.0	53.2	52.4	56.2

Target Price Range 2026 | 2027 | 2028

LEGENDS
— 28.00 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range
Low-High: $53-$94 Midpoint (% to Mid): $74 (25%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+30%)	10%
Low	55	(-5%)	3%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	310	308	339
to Sell	264	251	264
Hld's(000)	268661	267233	276172

Percent shares traded 30 20 10

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-6.7	0.8
3 yr.	18.8	65.7
5 yr.	51.0	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
28.95	30.13	27.23	25.77	25.59	23.90	24.68	26.09	23.29	22.92	23.37	24.25	24.11	23.12	25.29	29.51	29.80	30.15	Revenues per sh	30.75
3.08	3.88	3.47	3.70	3.65	3.82	4.06	4.22	4.59	4.88	5.29	5.61	5.89	6.24	6.42	6.69	7.85	8.20	"Cash Flow" per sh	9.00
.64	1.23	.93	1.33	1.45	1.53	1.66	1.74	1.89	1.98	2.17	2.32	2.39	2.64	2.58	2.84	3.05	3.30	Earnings per sh A	3.75
.20	.36	.50	.66	.84	.96	1.02	1.08	1.16	1.24	1.33	1.43	1.53	1.63	1.74	1.84	1.95	2.04	Div'd Decl'd per sh B ■	2.30
5.61	3.50	3.59	3.29	3.47	4.65	4.98	5.73	5.64	5.99	5.91	7.32	7.41	8.02	7.16	8.15	8.50	9.50	Cap'l Spending per sh	9.75
9.46	10.88	11.42	11.19	11.92	12.09	12.98	13.34	14.21	15.23	15.77	16.78	17.68	19.02	22.11	23.32	25.20	25.45	Book Value per sh C	26.00
225.15	226.41	227.89	249.60	254.10	264.10	266.10	275.20	277.16	279.21	281.65	283.37	283.86	288.94	289.76	291.27	292.00	295.00	Common Shs Outst'g D	300.00
26.8	10.9	13.6	12.5	13.6	15.1	16.3	17.3	18.3	20.9	21.3	20.3	24.3	23.3	23.6	22.9	Bold figures are		Avg Ann'l P/E Ratio	17.5
1.42	.66	.91	.80	.85	.96	.92	.91	.92	1.10	1.07	1.10	1.29	1.20	1.28	1.32	Value Line		Relative P/E Ratio	.95
1.2%	2.7%	4.0%	4.0%	4.3%	4.2%	3.8%	3.6%	3.4%	3.0%	2.9%	3.0%	2.6%	2.6%	2.9%	2.8%	estimates		Avg Ann'l Div'd Yield	3.5%
						6566.0	7179.0	6456.0	6399.0	6583.0	6873.0	6845.0	6680.0	7329.0	8596.0	8700	8900	Revenues ($mill)	9200
						454.0	479.0	525.0	553.0	610.0	659.0	682.0	757.0	751.0	833.0	900	980	Net Profit ($mill)	1130
						39.9%	34.3%	34.0%	33.1%	31.2%	14.9%	17.7%	15.0%	11.5%	10.3%	11.0%	11.0%	Income Tax Rate	11.0%
						2.0%	2.3%	2.7%	3.1%	1.1%	1.4%	2.1%	1.1%	1.5%	1.4%	2.0%	2.0%	AFUDC % to Net Profit	1.0%
						67.5%	68.7%	68.3%	67.1%	67.3%	69.0%	70.4%	71.2%	64.5%	65.3%	63.5%	62.5%	Long-Term Debt Ratio	61.5%
						32.2%	31.0%	31.4%	32.6%	32.4%	30.7%	29.4%	28.6%	34.2%	33.6%	35.5%	36.5%	Common Equity Ratio	37.5%
						10730	11846	12534	13040	13692	15476	17082	19223	18760	20205	20575	20475	Total Capital ($mill)	21000
						12246	13412	14705	15715	16761	18126	18926	21039	22352	22713	23800	25150	Net Plant ($mill)	27900
						6.0%	5.7%	5.7%	5.8%	5.9%	5.6%	5.3%	5.2%	5.3%	5.4%	5.5%	6.0%	Return on Total Cap'l	6.5%
						13.0%	12.9%	13.2%	12.9%	13.6%	13.8%	13.5%	13.7%	11.3%	11.9%	12.0%	12.5%	Return on Shr. Equity	14.0%
						13.1%	13.0%	13.3%	13.0%	13.7%	13.8%	13.6%	13.7%	11.6%	12.1%	12.0%	13.0%	Return on Com Equity E	14.0%
						5.2%	5.0%	5.2%	4.8%	5.2%	5.3%	4.9%	5.3%	3.8%	4.3%	4.5%	5.0%	Retained to Com Eq	5.5%
						60%	62%	61%	63%	62%	62%	64%	62%	68%	65%	64%	62%	All Div'ds to Net Prof	62%

CAPITAL STRUCTURE as of 3/31/23
Total Debt $14418 mill. **Due in 5 Yrs** $2324 mill.
LT Debt $12985 mill. LT Interest $580 mill.
Incl. $68 mill. finance leases.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $5 mill.
Pension Assets-12/22 $3599 mill. Oblig $3070 mill.
Pfd Stock $224 mill. **Pfd Div'd** $10 mill.
Incl. 373,148 shs. $4.50 $100 par, cum., callable at $110.00; 9,200,000 shs. 4.2%, $25 par, cum.
Common Stock 291,656,125 shs. as of 4/10/23
MARKET CAP: $16.7 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-3.1	+2.4	+3.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	8.14	8.46	8.78
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	8215	7951	8061
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+1.0	+1.0
Fixed Charge Cov. (%)	240	223	226

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	0.5%	2.5%	4.0%
"Cash Flow"	5.5%	5.5%	6.0%
Earnings	6.5%	6.0%	6.5%
Dividends	8.0%	7.0%	6.0%
Book Value	6.0%	7.5%	7.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	1864	1443	1575	1798	6680
2021	2013	1558	1725	2033	7329
2022	2374	1920	2024	2278	8596
2023	2284	2050	2150	2216	8700
2024	2335	2100	2200	2265	8900

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.85	.48	.76	.55	2.64
2021	1.09	.55	.54	.40	2.58
2022	1.20	.50	.56	.58	2.84
2023	.69	.70	.80	.86	3.05
2024	.80	.75	.85	.90	3.30

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.3825	.3825	.3825	.3825	1.53
2020	.4075	.4075	.4075	.4075	1.63
2021	.435	.435	.435	.435	1.74
2022	.46	.46	.46	.46	1.84
2023	.4875	.488			

BUSINESS: CMS Energy Corporation is a holding company for Consumers Energy, which supplies electricity and gas to lower Michigan (excluding Detroit). Has 1.9 million electric, 1.8 million gas customers. Has 1,836 megawatts of nonregulated generating capacity. Sold EnerBank in '21. Electric revenue breakdown: residential, 46%; commercial, 32%; industrial, 15%; other, 7%. Generating sources: coal, 29%; gas, 19%; renewables, 6%; purchased, 47%. Fuel costs: 34% of revenues. '22 depreciation rates: 3.7% electric, 2.9% gas, 8.9% other. Has 8,560 full-time employees. Chairman: John G. Russell. President & CEO: Garrick Rochow. Inc.: Michigan. Address: One Energy Plaza, Jackson, Michigan 49201. Telephone: 517-788-0550. Internet: www.cmsenergy.com.

CMS Energy started the year on a weak note. In the first quarter, the top line decreased nearly 4% year over year, to $2.28 billion. Meanwhile, earnings from continuing operations declined 43%, to $0.69 per share. The reduction was due to unfavorable weather, which reduced sales volumes and inflated service restoration costs during the period.

A gas rate application is expected in the fourth quarter. According to Michigan regulatory law, the Michigan Public Service Commission (MPSC) should give a ruling within 10 months of the utility's filing. Consumers Energy filed an application with the MPSC in December 2022, requesting an annual rate increase of $212 million based on a 10.25% return on equity. It's worth noting that the utility often requires rate relief because it operates a large system with aging equipment that needs to be replaced.

Decent growth in near-term earnings is probable. Consumers Energy is likely to see a boost from a $155 million increase in electric rates implemented at the beginning of 2023, as well as a full year's gas rate increase starting in October of last year. To offset the rising costs due to inflation, management is actively working to control expenses. All things considered, we estimate that earnings per share will advance at a single-digit pace in 2023 and 2024 each, to about $3.05 and $3.30, respectively.

The company is committed to improving its infrastructure and increasing its renewable energy portfolio while reducing costs. Over the next five years, the company is planning to invest $12.4 billion, with $6.1 billion focused on electric distribution, $6.3 billion on gas networks. It also intends to spend $3.1 billion on generating clean energy. The goal is to increase the percentage of renewable energy sources from 14% to 61% by 2040.

Shares of CMS Energy are ranked to underperform the broader market averages in the year ahead (Timeliness: 4). At the recent quotation, the equity has below-average capital appreciation potential over the 2026-2028 horizon. Still, the company has a track record of stable operating performance, which may interest some conservative accounts.

Emma Jalees *June 9, 2023*

(A) Diluted EPS. Excl. nonrec. gains (losses): '07, ($1.26); '09, (7¢); '10, 3¢; '11, 12¢; '12, (14¢); '17, (53¢); gains (losses) on disc. ops.: '07, (40¢); '09, 8¢; '10, (8¢); '11, 1¢; '12, 3¢; '21, $2.08; '22, 1¢. Next earnings report due early August. (B) Div'ds historically paid late Feb., May, Aug., & Nov. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '22: $7.80/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '22: 9.9% elec.; in '19: 9.9% gas; earned on avg. com. eq., '21: 13.2%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	65
Earnings Predictability	95

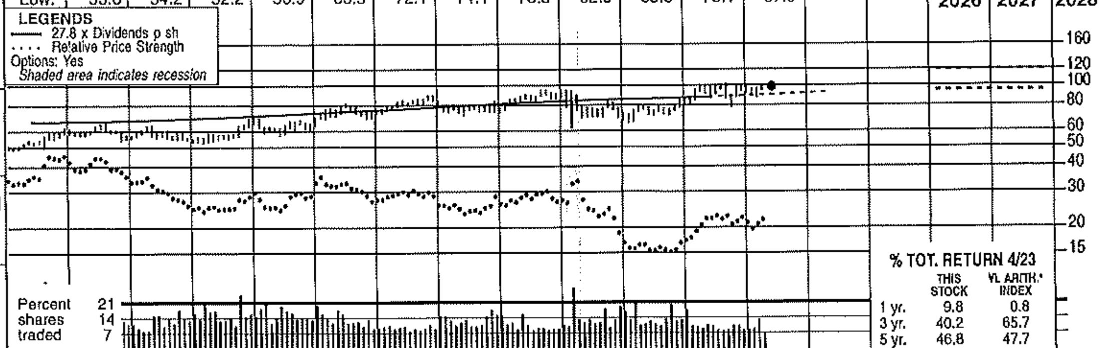
CON. EDISON NYSE-ED

RECENT PRICE 99.11 | P/E RATIO 20.4 (Trailing: 21.8; Median: 18.0) | RELATIVE P/E RATIO 1.21 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 3 Raised 4/28/23
SAFETY 1 New 7/27/90
TECHNICAL 3 Raised 4/28/23
BETA .75 (1.00 = Market)

High:	66.0	64.0	68.9	72.3	81.9	89.7	84.9	95.0	95.1	85.6	102.2	100.9
Low:	53.6	54.2	52.2	56.9	63.5	72.1	71.1	73.3	62.0	65.6	78.1	87.0

Target Price Range 2026 | 2027 | 2028



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$78-$118 $98 (0%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	120	(+20%)	8%
Low	95	(-5%)	3%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	471	467	532
to Sell	404	380	366
Hld's(000)	229945	232220	239865

Percent shares traded 21 14 7

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.8	0.8
3 yr.	40.2	65.7
5 yr.	46.8	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
48.23	49.62	46.36	45.69	44.17	41.62	42.27	44.11	42.85	39.59	38.82	38.44	37.80	35.78	38.63	44.15	*45.65*	*47.45*	Revenues per sh	*52.15*
5.77	5.99	5.86	6.24	6.61	7.15	7.45	7.30	7.93	7.89	8.41	8.92	9.39	9.70	10.08	10.36	*11.40*	*11.95*	"Cash Flow" per sh	*13.85*
3.48	3.36	3.14	3.47	3.57	3.86	3.93	3.62	4.05	3.94	4.10	4.55	4.37	4.17	4.38	4.55	*4.85*	*5.15*	Earnings per sh A	*6.00*
2.32	2.34	2.36	2.38	2.40	2.42	2.46	2.52	2.60	2.68	2.76	2.86	2.96	3.06	3.10	3.16	*3.24*	*3.34*	Div'd Decl'd per sh B ■	*3.86*
7.09	8.50	7.80	6.96	6.72	7.06	8.67	8.26	10.42	12.07	11.11	10.90	10.48	11.42	11.17	11.74	*15.75*	*14.50*	Cap'l Spending per sh	*16.00*
32.58	35.43	36.46	37.93	39.05	40.53	41.81	42.94	44.55	46.88	49.74	52.11	54.18	55.06	56.60	58.28	*58.70*	*60.55*	Book Value per sh C	*66.75*
272.02	273.72	281.12	291.62	292.89	292.87	292.87	292.88	293.00	305.00	310.00	320.96	332.63	342.30	353.98	354.96	*345.00*	*345.00*	Common Shs Outst'g D	*345.00*
13.8	12.3	12.5	13.3	15.1	15.4	14.7	15.9	15.6	18.8	19.8	17.1	19.7	19.0	17.2	20.3	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.73	.74	.83	.85	.95	.98	.83	.84	.79	.99	1.00	.92	1.05	.98	.93	1.18	*Value Line*		Relative P/E Ratio	*1.00*
4.8%	5.7%	6.0%	5.2%	4.5%	4.1%	4.3%	4.4%	4.1%	3.6%	3.4%	3.7%	3.4%	3.9%	4.1%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 12/31/22
Total Debt $23836 mill. Due in 5 Yrs $1579 mill.
LT Debt $20147 mill. LT Interest $987 mill.
(Total Interest Coverage: 2.9x)

Leases, Uncapitalized Annual rentals $64 mill.

Pension Assets-12/22 $14979 mill.
Oblig $12113 mill.

Pfd Stock None

Common Stock 355,045,021 shs.
as of 1/31/23

MARKET CAP: $35.2 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
12381	12919	12554	12075	12033	12337	12574	12246	13676	15670	*15750*	*16375*	Revenues ($mill)	*18000*
1157.0	1066.0	1193.0	1189.0	1266.0	1424.0	1438.0	1399.0	1528.0	1620.0	*1705*	*1785*	Net Profit ($mill)	*2075*
31.8%	34.0%	33.6%	35.3%	36.6%	20.1%	17.5%	12.9%	16.2%	15.4%	*18.0%*	*18.0%*	Income Tax Rate	*18.0%*
.5%	.3%	.7%	1.3%	1.5%	1.5%	1.9%	2.2%	2.1%	3.4%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*4.0%*
46.1%	48.0%	47.9%	50.8%	48.9%	51.1%	50.7%	52.0%	53.0%	49.3%	*48.5%*	*48.0%*	Long-Term Debt Ratio	*51.0%*
53.9%	52.0%	52.1%	49.2%	51.1%	48.9%	49.3%	48.0%	47.0%	50.7%	*51.5%*	*52.0%*	Common Equity Ratio	*49.0%*
22735	24207	25058	29033	30149	34221	36549	39229	42641	40834	*39400*	*40025*	Total Capital ($mill)	*47200*
28436	29827	32209	35216	37600	41749	43889	46555	48596	46766	*50000*	*52650*	Net Plant ($mill)	*60900*
6.4%	5.6%	6.0%	5.3%	5.4%	5.3%	5.1%	4.7%	4.7%	5.2%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
9.4%	8.5%	9.1%	8.3%	8.2%	8.5%	8.0%	7.4%	7.6%	7.8%	*8.5%*	*8.5%*	Return on Shr. Equity	*9.0%*
9.4%	8.5%	9.1%	8.3%	8.2%	8.5%	8.0%	7.4%	7.6%	7.8%	*8.5%*	*8.5%*	Return on Com Equity E	*9.0%*
3.6%	2.6%	3.5%	3.0%	3.0%	3.5%	2.9%	2.2%	2.5%	2.6%	*3.0%*	*3.0%*	Retained to Com Eq	*3.0%*
62%	69%	61%	64%	63%	59%	64%	70%	67%	67%	*67%*	*65%*	All Div'ds to Net Prof	*64%*

CECONY ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Electric Sales (GWH)	-6.5	-.5	3.3
Annual Residential Use (GWH)	11107	11344	11875
Annual Comm./Ind. Use (GWH)	9280	9250	10522
Annual Retail Choice (GWH)	22000	21549	21116
Annual Govt. & Other Use (GWH)	9164	9165	9507
% Change Customers (yr-end)	NA	NA	NA
Peak Load, Summer (Mw)	13170	13517	12424
ConEd Fixed Charge Cov. (%)	325	352	240

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-1.0%	-.5%	*4.5%*
"Cash Flow"	4.0%	4.5%	*5.5%*
Earnings	2.0%	1.5%	*5.5%*
Dividends	2.5%	3.0%	*3.5%*
Book Value	4.0%	4.0%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	3234	2719	3333	2960	12246
2021	3677	2971	3613	3415	13676
2022	4060	3415	4165	4031	15670
2023	*4150*	*3550*	*4275*	*3775*	*15750*
2024	*4325*	*3675*	*4450*	*3925*	*16375*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	1.35	.60	1.48	.74	4.17
2021	1.44	.53	1.41	1.00	4.38
2022	1.47	.64	1.63	.81	4.55
2023	*1.59*	*.67*	*1.71*	*.88*	*4.85*
2024	*1.71*	*.72*	*1.80*	*.92*	*5.15*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.74	.74	.74	.74	2.96
2020	.765	.765	.765	.765	3.06
2021	.775	.775	.775	.775	3.10
2022	.79	.79	.79	.79	3.16
2023	.81				

BUSINESS: Consolidated Edison, Inc. (ConEd) is a holding company for Consolidated Edison Company of New York (CECONY), which sells electricity, gas, and steam in most of NY city and Westchester County. ConEd also owns Orange and Rockland Utilities (O&R), which operates in New York and New Jersey. ConEd has 3.9 mill. electric, 1.2 mill. gas customers. Expected to close on the sale of its portfolio of renewable generation for $6.8 bill. by mid-2022. It entered into midstream gas joint venture 6/16; sold it 7/21. Purchases most of its power. Fuel costs: 26% of revenues. '22 reported deprec. rates: 3.0%-3.5%. Employs 14,319. Chrmn, President & CEO: Timothy Cawley. Inc.: NY. Addr.: 4 Irving Place, New York, NY 10003. Tel.: 212-460-4600. Internet: www.conedison.com.

Consolidated Edison has reached a favorable settlement agreement with key parties in its electric and gas rate review. In mid-February, the company announced it had come to terms with the Department of Public Service staff and other key parties. Negotiations had dragged on since the middle of last year, and the agreement is subject to the approval of the New York State Public Service Commission (NYSPSC). If it stands as is, the principles look reasonably favorable for ConEd. The holding company's larger of its two utilities, Consolidated Edison Company of New York (CECONY), will get a bump in its regulated return on equity (ROE), with the allowed return rising to 9.25% from 8.8% on a 48% common equity ratio. Roughly $11.8 billion in new authorized capital investment for 2026-2028, directed at reliability, safety, and clean energy objectives, is part of the settlement.

Assuming NYSPSC commissioners sign off on the deal, ConEd should post solid earnings gains over the next few years. (Note: first-quarter financial results were released just after our press cycle.) This year, electric and gas rate increases of $442 million and $217 million, respectively, would take effect. On the 12-month anniversary of those hikes, an additional $518 million in electric rates and $173 million in gas rates would take effect. And 24 months out, electric and gas rates would rise for the third-consecutive year, by $382 million and $122 million, respectively. Additionally, CECONY filed for a rate increase of $141 million six months ago for its steam service, effective November of this year. Taking the aforementioned figures into account, ConEd should see a few years of 6%-7% earnings gains.

At the recent stock valuation, most of the good news appears to be priced in. The company is looking better of late in terms of bottom-line growth prospects, as it will be the main beneficiary of New York's transition to a "green" energy future. However, the stock has been trading as if the 6%-7% share-earnings gains over the next two years are sustainable longer term. More likely, ConEd is apt to grow profits at a similar rate to the electric utility industry's 4.5%-5.5% per annum.

Anthony J. Glennon *May 12, 2023*

(A) Diluted EPS. Excl. nonrec. gains/losses: '13, d32¢; '14, 9¢; '16, 18¢; '17, 84¢; '18, d13¢; '19, d29¢; '20, d89¢; '21, d53¢; '22, 11¢. Excl. gain on disc. ops.: '08, $1.01. Next egs. report due early Aug. Quarterly figures may not sum to full year due to rounding. (B) Div'ds historically paid in mid-Mar., June, Sept., and Dec. ■ Div'd reinvestment plan available. (C) Incl. intang. In '22: $12.35/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. for CECONY in '20: 8.8%; O&R in '22: 9.2%. Regulatory Climate: Below Average.

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

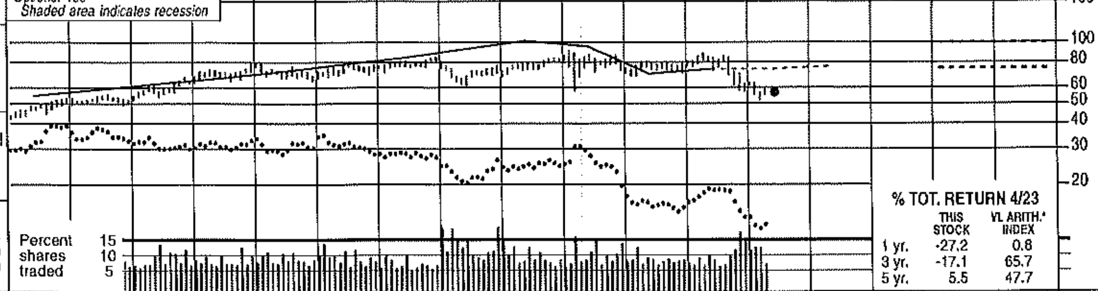
DOMINION ENERGY NYSE-D

RECENT PRICE 57.12 | P/E RATIO 14.3 (Trailing: 13.9; Median: 21.0) | RELATIVE P/E RATIO 0.85 | DIV'D YLD 4.7% | VALUE LINE

TIMELINESS 5 Lowered 4/21/23
SAFETY 2 Raised 9/11/98
TECHNICAL 5 Lowered 5/12/23
BETA .85 (1.00 = Market)

High:	55.6	68.0	80.9	79.9	79.0	85.3	81.7	83.9	90.9	81.1	88.8	63.9
Low:	48.9	51.9	63.1	64.5	66.3	70.9	61.5	67.4	57.8	67.9	57.2	52.0

LEGENDS
— 27.8 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2026 | 2027 | 2028

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$51-$102 $77 (35%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+75%)	18%
Low	75	(+30%)	11%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	699	690	660
to Sell	605	587	740
Hld's(000)	581334	589621	588391

Percent shares traded 15 10 5

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-27.2	0.8
3 yr.	-17.1	65.7
5 yr.	5.5	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
27.16	27.94	25.26	26.16	25.23	22.73	22.58	21.26	19.60	18.69	19.51	19.63	19.78	17.58	17.24	20.57	*20.80*	*21.15*	Revenues per sh	*23.00*
5.08	5.07	4.82	5.10	5.04	5.24	5.47	5.71	5.99	6.32	6.89	7.24	7.65	7.17	7.27	7.81	*7.75*	*8.05*	"Cash Flow" per sh	*9.15*
2.13	3.04	2.64	2.89	2.76	2.75	3.09	3.05	3.20	3.44	3.53	4.05	4.24	3.54	3.86	4.11	*4.00*	*4.20*	Earnings per sh A	*5.00*
1.46	1.58	1.75	1.83	1.97	2.11	2.25	2.40	2.59	2.80	3.04	3.34	3.67	3.45	2.52	2.67	*2.67*	*2.75*	Div'd Decl'd per sh B ■	*3.18*
6.88	6.10	6.41	5.89	6.41	7.20	7.06	9.14	9.35	9.69	8.53	6.25	5.94	7.47	7.36	9.09	*12.25*	*12.55*	Cap'l Spending per sh	*10.00*
16.30	17.28	18.67	20.65	20.08	18.35	20.04	19.75	21.25	23.26	26.58	29.53	35.33	29.44	31.51	31.26	*32.95*	*34.85*	Book Value per sh C	*42.15*
577.00	583.00	599.00	581.00	570.00	576.00	581.00	585.00	596.00	628.00	645.00	681.00	838.00	806.00	810.00	835.00	*842.00*	*851.00*	Common Shs Outst'g D	*870.00*
20.6	13.8	12.7	14.3	17.3	16.9	19.2	23.0	22.1	21.3	22.2	17.5	18.2	22.6	19.5	18.7	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*17.5*
1.09	.83	.85	.91	1.09	1.20	1.08	1.21	1.11	1.12	1.12	.95	.97	1.16	1.05	1.09	*estimates*		Relative P/E Ratio	*.95*
3.3%	3.8%	5.2%	4.4%	4.1%	4.1%	3.8%	3.4%	3.7%	3.8%	3.9%	4.7%	4.8%	4.3%	3.3%	3.5%			Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 12/31/22
Total Debt $45678 mill. Due in 5 Yrs $4900 mill.
LT Debt $38914 mill. LT Interest $1470 mill.
(Total interest coverage: 3.7x)
Leases, Uncapitalized Annual rentals $44 mill.

Pension Assets-12/22 $8694 mill. Oblig $8066 mill.
Pfd Stock $1783 mill. Pfd Divd $93 mill.

Common Stock 835,193,617 shs. as of 2/15/23

MARKET CAP: $47.7 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
13120	12436	11683	11737	12586	13366	16572	14172	13964	17174	*17500*	*18000*	Revenues ($mill)	*20000*
1806.0	1793.0	1899.0	2123.0	2244.0	2651.0	3447.0	3006.0	3191.0	3505.0	*3465*	*3660*	Net Profit ($mill)	*4460*
33.0%	28.1%	32.0%	22.8%	27.2%	17.3%	20.3%	12.2%	13.7%	16.3%	*16.0%*	*16.0%*	Income Tax Rate	*17.0%*
3.7%	4.5%	5.3%	7.5%	10.5%	5.1%	2.6%	3.4%	3.7%	3.2%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*4.0%*
61.9%	65.4%	65.1%	67.4%	64.4%	60.8%	51.4%	56.5%	56.4%	58.3%	*57.5%*	*58.0%*	Long-Term Debt Ratio	*57.5%*
37.3%	34.6%	34.9%	32.6%	35.6%	39.2%	45.0%	39.5%	38.5%	39.1%	*39.5%*	*39.5%*	Common Equity Ratio	*40.5%*
31229	33360	36280	44836	48090	51251	65818	60074	66344	66795	*69800*	*74700*	Total Capital ($mill)	*90400*
32628	36270	41554	49964	53758	54560	69082	57848	59774	63460	*70625*	*78025*	Net Plant ($mill)	*93500*
7.3%	6.6%	6.5%	6.0%	5.9%	6.5%	6.4%	6.2%	5.9%	6.0%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
15.2%	15.5%	15.0%	14.5%	13.1%	13.2%	10.8%	11.5%	11.0%	12.6%	*11.5%*	*11.5%*	Return on Shr. Equity	*11.5%*
15.4%	15.4%	15.0%	14.5%	13.1%	13.2%	11.6%	12.4%	12.2%	13.1%	*12.0%*	*12.0%*	Return on Com Equity E	*12.0%*
4.2%	3.3%	2.9%	2.7%	1.8%	2.3%	1.5%	.3%	4.3%	4.6%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
73%	79%	81%	81%	86%	82%	87%	98%	66%	66%	*67%*	*66%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (MWH)	-2.2	+.8	+2.0
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 (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	235	227	272

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-3.0%	-1.0%	*3.5%*
"Cash Flow"	4.0%	3.0%	*3.5%*
Earnings	3.0%	2.5%	*4.5%*
Dividends	4.0%	.5%	*1.5%*
Book Value	4.5%	5.5%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	3938	3106	3607	3521	14172
2021	3870	3038	3176	3880	13964
2022	4279	3596	4386	4913	17174
2023	*4475*	*3875*	*4550*	*4600*	*17500*
2024	*4700*	*3950*	*4700*	*4650*	*18000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.92	.73	1.08	.81	3.54
2021	1.09	.76	1.11	.90	3.86
2022	1.18	.77	1.11	1.06	4.11
2023	*1.01*	*.79*	*1.13*	*1.07*	*4.00*
2024	*1.13*	*.81*	*1.16*	*1.10*	*4.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.9175	.9175	.9175	.9175	3.67
2020	.94	.94	.94	.63	3.45
2021	.63	.63	.63	.63	2.52
2022	.6675	.6675	.6675	.6675	2.67
2023	.6675				

BUSINESS: Dominion Energy, Inc. (formerly Dominion Resources) is a holding company for Virginia Power, North Carolina Power, & South Carolina E&G, which serve 3.5 mill. customers in VA, SC, & NC. Serves 3.5 mill. gas customers in OH, WV, UT, SC, & NC. Other ops. incl. independent power production. Acq'd Questar 9/16; SCANA 1/19. Elec. rev. breakdown: residential, 47%; commercial, 34%; industrial, 8%; other, 11%. Generating sources: gas, 36%; nuclear, 28%; coal, 8%; other, 5%; purchased, 23%. Power/fuel costs: 31% of revs. '22 reported deprec. rates: 1.9%-3.9%. Employs 17,100. Chrmn., Pres. & CEO: Robert M. Blue. Inc.: VA. Address: 120 Tredegar St., P.O. Box 26532, Richmond, VA 23261-6532. Tel.: 804-819-2000. Internet: www.dominionenergy.com.

Leadership at Dominion Energy is still in the process of working through its "top-to-bottom review" of the business. First announced in November, CEO Robert Blue has described it as a complete analysis, which will include a look at alternatives to the current business mix and capital allocation. As of the February conference call with the investment community, management had not completed the process, but insisted that the current dividend level is safe. No full-year earnings targets are being provided by Dominion until a new strategic plan is in place. We cut our 2023 share-earnings estimate by $0.20 based on a seasonally mild winter and rising interest expense. (First-quarter financial results were due out shortly after this report went to press.) We've also scaled back our 2024 per-share profit target (by $0.15) based on the same macro challenges, namely having to refinance debt at higber rates.

The stock has been battered due to the uncertain direction of the company. Over the past six months, Dominion stock has underperformed the *Value Line Utility Index* hy 23 percentage points. The 6.5% long-term earnings growth rate the company was targeting last year now looks overly optimistic. The inflationary and rising interest-rate environment are very problematic and will probably make it difficult to achieve the returns Dominion management was banking on for some major upcoming projects, particularly its huge offshore wind farm. There's a good chance the company will divest some of its income-generating assets to help fund infrastructure investments. The natural gas pipeline distribution business and/or the liquefied natural gas operation could both be deemed nonstrategic holdings and therefore sold. While these moves would likely pay off down the road, near-term earnings would probably suffer.

Dominion stock is untimely. Utility investors with a longer-term leaning, however, may want to consider this issue. The company should see years of solid rate-base growth as it works to achieve the renewable energy targets of its state territories. That ought to eventually translate to above-average earnings and dividend growth relative to the utility peer group.

Anthony J. Glennon *May 12, 2023*

(A) Diluted egs. Excl. nonrec. gains/(losses): '08, 12¢; '09, (47¢); '10, $2.13; '11, (31¢); '12, ($2.18); '14, (81¢); '17, $1.19; '18, (31¢); '19, ($2.62); '20, ($1.72); '21, (67¢); '22, ($3.03); gain/(losses) from disc. ops.: '10, (26¢); '12, (4¢); '13, (16¢); '20, ($2.39); '21, 79¢; '22, 1¢. Next egs. report due early August. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '22: $20.78/sh. (D) In mill. (E) Rate base: Net orig. cost, adj. Rate all'd on com. eq. in VA in '22: 9.35%; in SC in '21: 9.5%. Reg. Clim.: Avg.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	30
Earnings Predictability	100

DTE ENERGY CO. NYSE-DTE

RECENT PRICE 106.51 | P/E RATIO 17.2 (Trailing: 18.9; Median: 18.0) | RELATIVE P/E RATIO 1.05 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 4 Lowered 12/30/22
SAFETY 2 Raised 12/21/12
TECHNICAL 3 Raised 6/2/23
BETA .95 (1.00 = Market)

High:	62.6	73.3	90.8	92.3	100.4	116.7	121.0	134.4	135.7	145.4	140.2	121.3	
Low:	52.5	60.3	64.8	73.2	78.0	96.6	94.3	107.3	71.2	108.2	100.6	102.3	

Target Price Range 2026 | 2027 | 2028

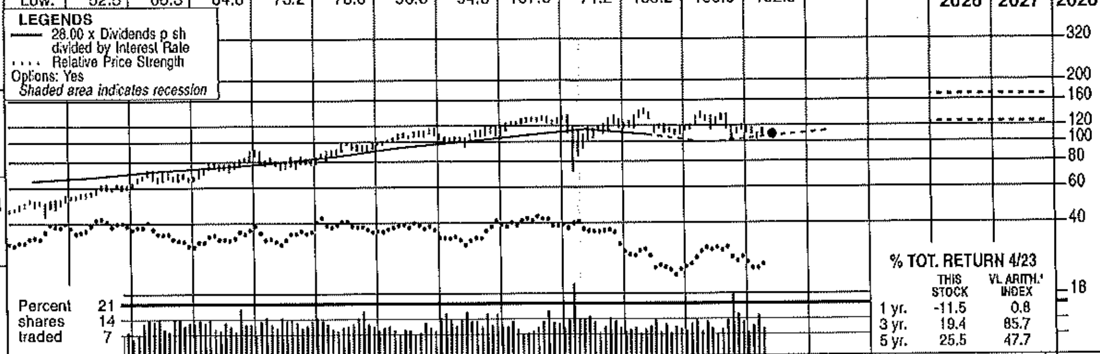
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$91-$150 $121 (15%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	170	(+60%)	15%
Low	125	(+15%)	8%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	363	306	399
to Sell	267	304	260
Hld's(000)	143263	145343	153190



% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-11.5	0.8
3 yr.	19.4	85.7
5 yr.	25.5	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
54.28	57.23	48.45	50.51	52.57	51.01	54.56	69.50	57.60	59.24	70.28	78.12	65.91	62.84	77.23	93.48	*82.75*	*90.00*	Revenues per sh	*92.25*
8.48	8.26	9.38	9.78	9.57	9.77	10.13	11.85	9.44	10.60	11.77	12.58	12.97	14.70	11.94	12.65	*14.05*	*14.50*	"Cash Flow" per sh	*17.05*
2.66	2.73	3.24	3.74	3.67	3.88	3.76	5.10	4.44	4.83	5.73	6.17	6.31	7.08	4.10	5.52	*6.20*	*6.70*	Earnings per sh A	*8.30*
2.12	2.12	2.12	2.18	2.32	2.42	2.59	2.69	2.84	3.06	3.36	3.59	3.85	4.12	3.88	3.54	*3.81*	*4.05*	Div'd Decl'd per sh B ■	*4.65*
7.96	8.42	6.26	6.49	8.77	10.56	10.59	11.58	11.26	11.40	12.54	14.91	15.59	19.91	19.47	16.42	*17.05*	*17.50*	Cap'l Spending per sh	*18.50*
35.86	36.77	37.96	39.67	41.41	42.78	44.73	47.05	48.88	50.22	53.03	56.27	60.73	64.12	44.93	46.35	*52.95*	*54.25*	Book Value per sh C	*60.75*
163.23	163.02	165.40	169.43	169.25	172.35	177.09	176.99	179.47	179.43	179.39	181.93	192.21	193.77	193.75	205.69	*205.50*	*205.50*	Common Shs Outst'g D	*206.00*
18.3	14.8	10.4	12.3	13.5	14.9	17.9	14.9	18.1	19.0	18.6	17.4	19.9	16.3	30.0	22.4	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.97	.89	.69	.78	.85	.95	1.01	.78	.91	1.00	.94	.94	1.06	.84	1.62	1.30	*Value Line*		Relative P/E Ratio	*1.00*
4.4%	5.2%	6.3%	4.8%	4.7%	4.2%	3.8%	3.5%	3.5%	3.3%	3.2%	3.3%	3.1%	3.6%	3.2%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 3/31/23
Total Debt $19385 mill. Due in 5 Yrs $6481 mill.
LT Debt $17662 mill. LT Interest $514 mill.
Incl. $209 mill. securitization bonds. Incl. $19 mill. finance leases.
(LT interest earned: 1.7x)
Leases, Uncapitalized Annual rentals $16 mill.

Pension Assets-12/22 $5507 mill. Oblig $5857 mill.

Pfd Stock None
Common Stock 206,109,174 shs.

MARKET CAP: $21.9 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
9661.0	12301	10337	10630	12607	14212	12669	12177	14964	19228	*17000*	*18500*	Revenues ($mill)	*19000*
661.0	905.0	796.0	868.0	1029.0	1120.0	1169.0	1368.0	796.0	1135.4	*1275*	*1375*	Net Profit ($mill)	*1710*
27.5%	28.5%	25.6%	24.5%	21.8%	8.1%	11.5%	10.9%	--	2.6%	*5.0%*	*5.0%*	Income Tax Rate	*5.0%*
3.5%	4.1%	4.3%	3.6%	3.5%	3.8%	3.3%	3.4%	4.9%	4.0%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
47.7%	50.0%	50.2%	55.6%	56.2%	54.2%	57.7%	60.5%	62.5%	63.0%	*61.5%*	*61.5%*	Long-Term Debt Ratio	*61.0%*
52.3%	50.0%	49.8%	44.4%	43.8%	45.8%	42.3%	39.5%	37.5%	37.0%	*38.5%*	*38.5%*	Common Equity Ratio	*39.0%*
15135	16670	17607	20280	21697	22371	27607	31426	23236	25158	*28250*	*29000*	Total Capital ($mill)	*32200*
15800	16820	18034	19730	20721	21650	25317	27969	26944	28767	*31050*	*31500*	Net Plant ($mill)	*36600*
5.7%	6.6%	5.7%	5.3%	5.9%	6.1%	5.3%	5.4%	4.7%	4.4%	*5.0%*	*5.0%*	Return on Total Cap'l	*6.0%*
8.3%	10.9%	9.1%	9.6%	10.8%	10.9%	10.0%	11.0%	9.1%	13.0%	*11.5%*	*11.5%*	Return on Shr. Equity	*12.5%*
8.3%	10.9%	9.1%	9.6%	10.8%	10.9%	10.0%	11.0%	9.1%	13.0%	*11.5%*	*11.5%*	Return on Com Equity E	*12.5%*
2.7%	5.2%	3.4%	3.7%	4.6%	4.9%	4.1%	4.9%	.1%	2.0%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
67%	52%	63%	61%	58%	55%	59%	56%	99%	76%	*60%*	*60%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-3.4	+2.1	-1.4
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)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	268	233	264

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	3.0%	2.5%	*5.0%*
"Cash Flow"	3.0%	4.5%	*4.5%*
Earnings	4.0%	2.5%	*4.5%*
Dividends	5.5%	5.5%	*3.0%*
Book Value	3.0%	1.5%	*1.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	3022	2583	3284	3288	12177
2021	3581	3021	3715	4647	14964
2022	4577	4924	5251	4476	19228
2023	3779	*3850*	*4821*	*4550*	*17000*
2024	*4575*	*4550*	*4850*	*4525*	*18500*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	1.76	1.44	2.46	1.42	7.08
2021	1.65	.60	.30	1.55	4.10
2022	2.03	.19	1.99	1.31	5.52
2023	1.33	*1.10*	*2.10*	*1.67*	*6.20*
2024	*2.30*	*1.20*	*1.90*	*1.30*	*6.70*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.945	.945	.945	.945	3.78
2020	1.0125	1.0125	1.0125	1.0125	4.05
2021	.9225	.9225	.9225	.825	3.59
2022	.885	.885	.885	.885	3.54
2023	.9525	.9525			

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: 2.2 mill. electric, 1.3 mill. gas. Has various nonutility operations. Electric revenue breakdown: residential, 50%; commercial, 33%; industrial, 11%; other, 6%. Generating sources: coal, 67%; nuclear, 17%; gas, 1%; purchased, 15%. Fuel costs: 62% of revenues. '22 reported deprec. rates: 4.2% electric, 2.9% gas. Has 10,600 employees. Chairman, President & CEO: Jerry Norcia. Incorporated: Michigan. Address: One Energy Plaza, Detroit, Michigan 48226-1279. Tel.: 313-235-4000. Internet: www.dteenergy.com.

DTE Energy's electric utility subsidiary has filed another general rate case. This request comes just months after Michigan regulators rejected a majority of rate increases, largely due to customer pushback at public hearings. The utility is seeking an increase of $622 million, compared to the 2022 initial request of $388 million. While rate cases should help ease the costs of the transition to providing cleaner, more reliable energy, we think The Michigan Public Service Commission will likely give the utility an unfavorable ruling, given the prior rate case in November.

We have slightly lowered our full-year 2023 earnings estimate. DTE has a low return on total capital and relies on heavy debt levels. The interest rate environment and inflationary pressures should continue to raise borrowing costs and challenge margins in the short term. Accordingly, the company had higher rate base costs in the first quarter. On a positive note, rate relief and the Inflation Reduction Act will likely benefit performance in the short term and boost growth. We look for earnings of $6.20 per share, just shy of management's EPS midpoints and within DTE Energy's yearly target of 5%-7% profit growth.

The utility is committed to improving the electric grid. The company plans to invest $9 billion in the grid over the next five years. The investment will enhance tree trimming, improve maintenance and infrastructure, and accelerate the full automation of the electric grid, which will reduce the duration of outages. The utility plans to fully automate the grid within 5-6 years.

DTE Energy shares have continued to struggle of late. Indeed, the stock dropped more than 6% since our March review, and is now down more than 20% over the past 12 months. These shares are ranked 4 (Below Average) for Timeliness. Conversely, income-oriented investors may be drawn to the utility's dividend yield of 3.6%, which is in line with the strong industry average. Too, the utility has a solid potential dividend growth rate of 3.0%. The stock also has a high mark for Price Stability, and is ranked Above Average (2) for Safety.

Zachary J. Hodgkinson *June 9, 2023*

(A) Diluted EPS. Excl. nonrec. gains (loss): '07, $1.96; '08, 50¢; '11, 51¢; '15, (39¢); '17, 59¢; gains (losses) on discontinued operations: '07, $1.20; '08, 13¢; '12, (33¢); '21, 57¢. Next earnings report due late July. (B) Div'ds paid mid-Jan., Apr., July & Oct. ■ Div'd reinvestment plan available. (C) Incl. intang. In '22: $29.20/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on common equity in '20: 9.9% elec.; in '22: 9.9% gas; earned on avg. com. eq., '21: 7.6%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	60
Earnings Predictability	65

DUKE ENERGY NYSE-DUK

RECENT PRICE 99.09 | P/E RATIO 17.5 (Trailing: 18.6 Median: 18.0) | RELATIVE P/E RATIO 1.04 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Raised 2/24/23
SAFETY 2 New 6/1/07
TECHNICAL 3 Raised 4/28/23
BETA .85 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$82-$136 $109 (10%)

2026-28 PROJECTIONS

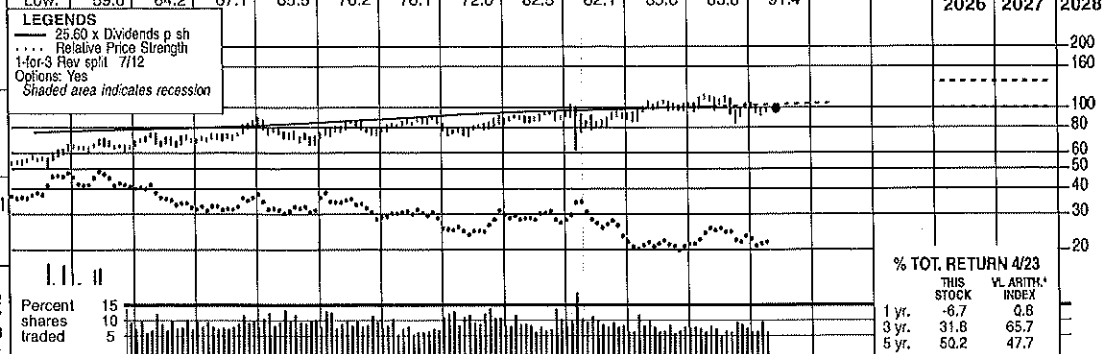
	Price	Gain	Ann'l Total Return
High	135	(+35%)	11%
Low	100	(Nil)	4%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	877	868	947
to Sell	688	675	673
Hld's(000)	491735	491683	499614

High:	71.1	75.5	87.3	90.0	87.8	91.8	91.4	97.4	103.8	108.4	116.3	106.4
Low:	59.6	64.2	67.1	65.5	70.2	76.1	72.0	82.5	62.1	85.6	83.8	91.4

Target Price Range 2026 2027 2028



% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-6.7	0.8
3 yr.	31.8	65.7
5 yr.	50.2	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
30.24	31.15	29.18	32.22	32.63	27.88	34.84	33.84	34.10	32.49	33.66	33.73	34.21	31.04	32.64	37.36	*37.35*	*37.65*	Revenues per sh	*39.60*
8.11	7.34	7.58	8.49	8.68	6.80	8.56	9.11	9.40	9.20	10.01	11.05	12.12	12.04	12.60	12.91	*13.30*	*13.55*	"Cash Flow" per sh	*14.60*
3.60	3.03	3.39	4.02	4.14	3.71	3.98	4.13	4.10	3.71	4.22	4.72	5.06	5.12	5.24	5.27	*5.65*	*6.00*	Earnings per sh A	*7.00*
2.58	2.70	2.82	2.91	2.97	3.03	3.09	3.15	3.24	3.36	3.49	3.64	3.75	3.82	3.90	3.98	*4.06*	*4.14*	Div'd Decl'd per sh B ■	*4.30*
7.43	10.35	9.85	10.84	9.80	7.81	7.83	7.62	9.83	11.29	11.50	12.91	15.17	12.88	12.63	14.76	*16.75*	*17.60*	Cap'l Spending per sh	*16.75*
50.40	49.51	49.85	50.84	51.14	58.04	58.54	57.81	57.74	58.62	59.63	60.27	61.20	59.82	61.55	61.51	*64.50*	*66.25*	Book Value per sh C	*70.00*
420.62	423.96	436.29	442.96	445.29	704.00	706.00	707.00	688.00	700.00	700.00	727.00	733.00	769.00	769.00	770.00	*770.00*	*770.00*	Common Shs Outst'g D	*770.00*
16.1	17.3	13.3	12.7	13.8	17.5	17.4	17.9	18.2	21.3	19.9	17.0	17.7	17.1	18.9	19.6	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.85	1.04	.89	.81	.87	1.11	.98	.94	.92	1.12	1.00	.92	.94	.88	1.02	1.14	*Value Line*		Relative P/E Ratio	*.95*
4.4%	5.2%	6.2%	5.7%	5.2%	4.7%	4.4%	4.3%	4.3%	4.3%	4.2%	4.5%	4.2%	4.4%	3.9%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*3.9%*

CAPITAL STRUCTURE as of 12/31/22
Total Debt $75170 mill. **Due in 5 Yrs** $19536 mill.
LT Debt $67061 mill. **LT Interest** $2206 mill.
Incl. $915 mill. finance leases.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $225 mill.
Pension Assets-12/21 $9235 mill.
Oblig $8207 mill.
Pfd Stock $1962 mill. **Pfd Div'd** $107 mill.
40 mill. shs. 5.75%, cum., $25 liq. value, redeemable at $25.50 prior to 6/15/24; 1 mill. shs. 4.875%, cum., $1000 liq. value.
Common Stock 770,080,285 shs. as of 10/31/22
MARKET CAP: $76.2 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
24598	23925	23459	22743	23565	24521	25079	23868	25097	28768	*28750*	*29500*	Revenues ($mill)	*31500*
2813.0	2934.0	2854.0	2560.0	2963.0	3339.0	3747.0	3878.0	4133.0	4104.1	*4350*	*4620*	Net Profit ($mill)	*5390*
32.6%	30.6%	32.2%	31.0%	30.4%	14.1%	12.7%	.3%	5.1%	7.4%	*9.0%*	*9.0%*	Income Tax Rate	*9.0%*
8.8%	7.2%	9.2%	11.7%	12.3%	11.4%	8.0%	6.9%	5.9%	*8.0%*	*7.0%*	*7.0%*	AFUDC % to Net Profit	*7.0%*
48.0%	47.7%	48.6%	52.6%	54.0%	53.8%	54.0%	53.7%	55.1%	*56.5%*	*58.5%*	*58.5%*	Long-Term Debt Ratio	*61.0%*
52.0%	52.3%	51.4%	47.4%	46.0%	46.2%	44.1%	44.4%	43.1%	*42.0%*	*40.0%*	*40.0%*	Common Equity Ratio	*37.5%*
79482	78088	77222	86609	90774	94940	101807	103589	109744	*115150*	*124525*	*124525*	Total Capital ($mill)	*144100*
69490	70046	75709	82520	86391	91694	102127	106782	111408	111748	*124375*	*124375*	Net Plant ($mill)	*141100*
4.6%	4.8%	4.8%	4.0%	4.3%	4.6%	4.7%	4.8%	4.8%	4.5%	*4.5%*	*4.5%*	Return on Total Cap'l	*4.5%*
6.8%	7.2%	7.2%	6.2%	7.1%	7.6%	8.0%	8.1%	8.4%	8.5%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.0%*
6.8%	7.2%	7.2%	6.2%	7.1%	7.6%	8.3%	8.2%	8.5%	8.5%	*9.0%*	*9.0%*	Return on Com Equity E	*9.0%*
1.5%	1.7%	1.5%	.6%	1.2%	2.0%	2.4%	2.3%	1.9%	2.5%	*2.5%*	*2.5%*	Retained to Com Eq	*3.0%*
78%	76%	79%	91%	83%	74%	71%	73%	78%	76%	*73%*	*73%*	All Div'ds to Net Prof	*68%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-2.3	+2.0	NA
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.)	NA	NA	NA
Fixed Charge Cov. (%)	183	209	285

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '26-'27
Revenues	.5%	-.5%	2.5%
"Cash Flow"	4.0%	5.0%	5.0%
Earnings	3.0%	4.5%	5.0%
Dividends	3.0%	3.5%	2.0%
Book Value	2.0%	1.0%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	5949	5421	6721	5777	23868
2021	6150	5758	6951	6238	25097
2022	7132	6685	7968	6983	28768
2023	*7050*	*6750*	*7875*	*7075*	*28750*
2024	*7450*	*6850*	*7950*	*7250*	*29500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	1.14	1.08	1.87	1.03	5.12
2021	1.26	1.15	1.88	.94	5.24
2022	1.30	1.14	1.78	1.11	5.27
2023	*1.30*	*1.15*	*2.00*	*1.20*	*5.65*
2024	*1.35*	*1.30*	*2.05*	*1.30*	*6.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.9275	.9275	.945	.945	3.75
2020	.945	.945	.965	.965	3.82
2021	.965	.965	.985	.985	3.90
2022	.985	.985	1.005	1.005	3.98
2023	1.005				

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.6 mill. elec. customers in NC, FL, IN, SC, OH, & KY, and 1.6 mill. gas customers in OH, KY, NC, SC, and TN. Owns independent power plants & has 25% stake in National Methanol in Saudi Arabia. Acq'd Progress Energy 7/12; Piedmont Natural Gas 10/16; discontinued most int'l ops. in '16. Elec. rev. breakdown: residential, 45%; commercial, 28%; industrial, 13%; other, 14%. Generating sources: gas, 32%; nuclear, 30%; coal, 18%; other, 1%; purchased, 19%. Fuel costs: 28% of revs. '22 reported deprec. rate: 3.6%. Has 27,600 employees. Chairman, President & CEO: Lynn J. Good. Inc.: DE. Address: 550 South Tryon St., Charlotte, NC 28202-1803. Tel.: 704-382-3853. Internet: www.duke-energy.com.

We expect Duke Energy's earnings to advance nicely in 2023. The company should continue to benefit from rate relief and strong electric volume growth. The pending sale of the company's unregulated commercial renewables operations will also likely improve earnings prospects. Accordingly, our 2023 EPS target is at the midpoint of management's guidance of $5.55-$5.75. The macroeconomic environment, including rising interest rates and inflation should also improve over that interim and benefit the bottom line. The utility remains committed to its cost mitigation target of $300 million in 2023, and expects 75% of the savings to be sustainable into the next few years. As such, we look for 2024 earnings of $6.00 per share, near the company's growth target of between 5%-7%.

Duke Energy has a number of cases pending. In North Carolina, Duke Energy Carolinas is seeking to raise residential rates by 17.9% over three years, to improve the electricity grid and provide solar investments. In Kentucky, the utility requested a $75.2 million (17.8%) hike. The company has made more than $300 million in investments in Kentucky to strengthen and improve the electricity grid, since the last rate case was approved in 2020.

The company remains focused on the development of clean and renewable energy projects and carbon reduction. The North Carolina Utilities Commission recently provided approval of 3,100 megawatts of solar and 1,600 megawatts of storage. That entity also supported planning for 2,000 megawatts of new natural gas, as part of an orderly transition out of coal by 2035. Duke Energy intends to reach 30,000 megawatts of renewable energy by 2035, and achieve net-zero carbon emissions by 2050 in its clean energy transition.

This stock has a dividend yield of 4.1%, compared to the utility average of about 3.7%. Duke has consistently proven to be one of the better managed utilities in the sector. The stock's price has outperformed its peer group over that past 5- and 10-year periods, and we see no reason why it shouldn't do the same over the next three to five years.

Zachary J. Hodgkinson *May 12, 2023*

(A) Dil. EPS. Excl. net nonrec. losses: '12, 64¢; '13, 22¢; '14, 59¢; '15, 5¢; '16, 60¢; '18, 96¢; '20, $3.40; '21, 30¢; 1Q22, 22¢; net nonrec gain: '17, 14¢. 2021 EPS don't sum to annual due to rounding. Next egs. due early Aug. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '22: $41.34/sh. (D) In mill., adj. for rev. split. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '21 in NC: 9.6%; in '19 in SC: 9.5%; in '20 in FL: 9.5%-11.5%; in '20 in IN: 9.7%. Reg. Clim.: NC, SC Avg.; OH, IN Above Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	100

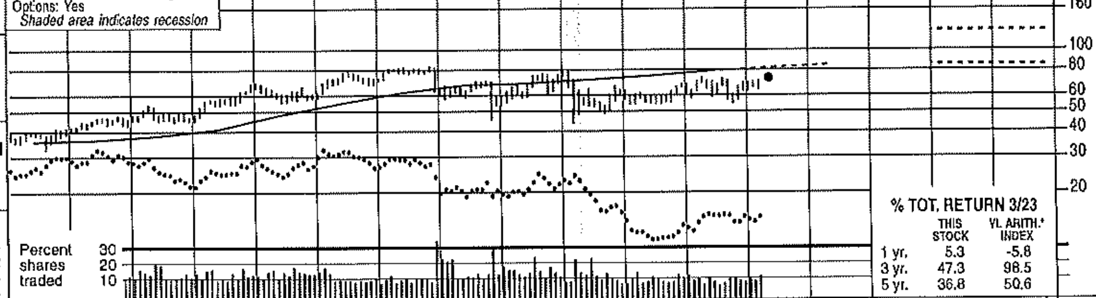
EDISON INTERNAT'L NYSE-EIX

RECENT PRICE	72.84	P/E RATIO	15.9 (Trailing: 45.2; Median: 20.0)	RELATIVE P/E RATIO	0.92	DIV'D YLD	4.0%	VALUE LINE

TIMELINESS 3 Raised 3/10/23
SAFETY 3 Lowered 11/23/18
TECHNICAL 3 Lowered 3/10/23
BETA .95 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	48.0	54.2	68.7	69.6	78.7	83.4	71.0	76.4	78.9	68.6	73.3	72.9
Low:	39.6	44.3	44.7	55.2	58.0	62.7	45.5	53.4	43.6	53.9	54.4	62.9

LEGENDS
— 27.8 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2026 | 2027 | 2028

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
\$56-\$102	\$79 (10%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	125	(+70%)	17%
Low	85	(+15%)	8%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	368	339	382
to Sell	254	277	254
Hld's(000)	333217	335090	343385

Percent shares traded 30 / 20 / 10

% TOT. RETURN 3/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.3	-5.8
3 yr.	47.3	98.5
5 yr.	36.8	50.6

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
40.25	43.31	37.98	38.09	39.16	36.41	38.61	41.17	35.37	36.43	37.81	38.85	34.11	35.83	39.18	45.05	*44.70*	*46.40*	Revenues per sh	*49.50*
7.60	8.08	7.96	8.41	9.03	9.63	8.80	9.95	10.35	10.43	11.03	4.69	9.15	7.94	8.58	9.35	*11.45*	*12.10*	"Cash Flow" per sh	*14.15*
3.32	3.68	3.24	3.35	3.23	4.55	3.78	4.33	4.15	3.94	4.51	d1.26	3.98	1.72	2.00	1.60	*4.70*	*5.10*	Earnings per sh A	*6.45*
1.18	1.23	1.25	1.27	1.29	1.31	1.37	1.48	1.73	1.98	2.23	2.43	2.48	2.58	2.69	2.84	*2.95*	*3.05*	Div'd Decl'd per sh B ■	*3.65*
8.67	8.67	10.07	13.94	14.76	12.73	11.05	11.99	12.97	11.46	11.75	13.84	13.47	14.47	14.47	15.12	*15.25*	*15.75*	Cap'l Spending per sh	*17.00*
25.92	29.21	30.20	32.44	30.86	28.95	30.50	33.64	34.89	36.82	35.82	32.10	36.75	37.08	36.57	30.72	*37.00*	*40.00*	Book Value per sh C	*48.50*
325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	361.99	378.91	380.38	382.21	*384.00*	*386.00*	Common Shs Outst'g D	*390.00*
16.0	12.4	9.7	10.3	11.8	9.7	12.7	13.0	14.8	17.9	17.2	--	16.7	34.9	29.7	40.6	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.85	.75	.65	.66	.74	.62	.71	.68	.75	.94	.87	--	.89	1.79	1.61	2.36	*Value Line*		Relative P/E Ratio	*.90*
2.2%	2.7%	4.0%	3.7%	3.4%	3.0%	2.8%	2.6%	2.8%	2.8%	2.9%	3.8%	3.7%	4.3%	4.5%	4.4%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 12/31/22
Total Debt \$31654 mill. Due in 5 Yrs \$9685 mill.
LT Debt \$27025 mill. LT Interest \$1170 mill.
(LT interest earned: 1.6x)
Leases, Uncapitalized Annual rentals \$542 mill.
Pension Assets-12/22 \$3462 mill.
Oblig \$3524 mill.

Pfd Stock \$1978 mill. Pfd Div'd \$99 mill.

Common Stock 382,566,466 shs.

as of 1/31/23
MARKET CAP: \$27.9 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
12581	13413	11524	11869	12320	12657	12347	13578	14905	17220	*17170*	*17900*	Revenues (\$mill)	*19300*
1344.0	1539.0	1480.0	1422.0	1603.0	d290.0	1477.0	775.0	925.0	824.0	*1800*	*1970*	Net Profit (\$mill)	*2515*
25.2%	22.4%	6.6%	11.1%	5.0%	--	--	--	--	--	*5.0%*	*5.0%*	Income Tax Rate	*5.0%*
7.8%	5.8%	8.0%	6.8%	7.2%	--	11.1%	22.5%	18.5%	18.5%	*15.0%*	*12.0%*	AFUDC % to Net Profit	*8.0%*
45.7%	44.1%	45.0%	41.8%	45.6%	53.6%	53.5%	55.2%	57.6%	63.4%	*61.5%*	*61.0%*	Long-Term Debt Ratio	*60.5%*
46.2%	47.2%	46.7%	49.2%	45.8%	38.3%	39.9%	39.5%	33.2%	27.5%	*29.5%*	*30.0%*	Common Equity Ratio	*32.0%*
21516	23216	24352	24362	25506	27284	33360	35581	41959	42646	*45000*	*47500*	Total Capital (\$mill)	*60000*
30455	32981	35085	37000	39050	41348	44285	47839	50700	53486	*57000*	*60000*	Net Plant (\$mill)	*69000*
7.3%	7.7%	7.1%	6.9%	7.3%	.1%	5.6%	3.4%	3.3%	3.3%	*5.0%*	*5.5%*	Return on Total Cap'l	*6.0%*
11.5%	11.9%	11.1%	10.0%	11.6%	NMF	9.5%	4.9%	5.2%	5.3%	*10.0%*	*10.5%*	Return on Shr. Equity	*11.5%*
12.5%	13.0%	12.0%	10.8%	12.7%	NMF	10.2%	4.6%	5.5%	6.2%	*12.0%*	*12.0%*	Return on Com Equity E	*13.5%*
8.1%	8.8%	7.2%	5.6%	6.6%	NMF	4.1%	NMF	NMF	NMF	*5.0%*	*5.0%*	Retained to Com Eq	*6.0%*
40%	37%	44%	53%	52%	NMF	63%	NMF	NMF	NMF	*62%*	*60%*	All Div'ds to Net Prof	*57%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	+.7	-3.9	+2.6
Avg. Indust. Use (MWH)	589	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	23133	21190	24346
Annual Load Factor (%)	46.7	52.7	45.8
% Change Customers (yr-end)	+.6	+.3	+.8
Fixed Charge Cov. (%)	NMF	113	135

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	0.5%	2.0%	3.5%
"Cash Flow"	-0.5%	-4.0%	8.5%
Earnings	-7.0%	-16.0%	10.0%
Dividends	7.5%	6.5%	5.0%
Book Value	1.0%	-0.5%	5.5%

Cal-endar	QUARTERLY REVENUES (\$ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	2790	2987	4644	3157	13578
2021	2960	3315	5299	3331	14905
2022	3968	4008	5228	4016	17220
2023	*3910*	*4000*	*5660*	*3600*	*17170*
2024	*4100*	*4200*	*5800*	*3800*	*17900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.50	.85	d.76	1.13	1.72
2021	.68	.84	d.90	1.38	2.00
2022	.22	.63	d.33	1.09	1.60
2023	*1.00*	*.90*	*1.60*	*1.20*	*4.70*
2024	*1.10*	*1.00*	*1.70*	*1.30*	*5.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.6125	.6125	.6125	.6125	2.45
2020	.6375	.6375	.6375	.6375	2.55
2021	.6625	.6625	.6625	.6625	2.65
2022	.70	.70	.70	.70	2.80
2023	.738				

BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison Company (SCE), which supplies electricity to 5.2 mill. customers in a 50,000-sq.-mi. area in central, coastal, & southern CA (excl. Los Angeles & San Diego). Edison Energy is an energy svcs. co. Disc. Edison Mission Energy (independent power producer) in '12. Elec. rev. breakdown: residential, 40%; commercial, 42%; industrial, 3%; other, 15%. Generating sources: nuclear, 9%; gas, 7%; hydro, 4%; purch., 80%. Power costs: 37% of revs. '22 reported depr. rate: 3.8%. Has 13,385 empls. Chairman: William P. Sullivan. Pres. & CEO: Pedro J. Pizarro. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Web: www.edison.com.

Edison International has introduced an adjusted earnings bracket for its expectations this year. Along with a solid fourth-quarter report to close out 2022, management guided EPS for this year to a range of \$4.55 to \$4.85. Of course, EIX's annual performance can be dramatically effected by negatives tied to the wildfire-related lawsuits and the settlement that go along with them. The company has been dealing with such swings since 2017 and this phenomenon is the primary reason why this stock's Earnings Predictability is so low (10 out of 100). That said, Edison has put in the work (and funding) to reduce the risks its operations were exposed to (more color below) and we expect smoother sailing ahead.

Adjusted earnings are apt to improve by more than 8% in 2024. Energy demand in California is rising year over year and the company has numerous green programs lined up to cater to these needs. Moreover, there should be some rate relief coming in the pipeline, but the finality of such is in the hands of the California Public Utilities Commission (CPUC), which is not known for its overly business-friendly decisions. It is not all the CPUC's fault, as that state has had its financial troubles stemming from the pandemic. Regardless, EIX has been spending and the recouping of these expenditures, as well as an improved return on equity look to be in the near-term cards. With that, adjusted earnings of \$5.10 should be in reach next year.

A new three-year wildfire plan is the next step in improving grid safety. The company has reduced the probability of wildfires tied to its equipment by roughly 80% via the usage of covered conductor (coated wire). The 2023-2025 goals are further grid hardening, enhanced vegetation management, and improved situational awareness during dangerous weather. Drones and helicopters will be utilized for monitoring structures. Also, by 2025, 7,200 miles (75%) of overhead distribution power lines in high-risk areas will be covered.

With a yield north of 4%, the income-minded should take a look. Long-term accounts should look elsewhere, however, as this selection does not stand out for the coming 18 months or 3- to 5-year stretch.

Erik M. Manning *April 21, 2023*

(A) Dil. EPS. Excl. nonrec. gains (losses): '10, 54¢; '11, (\$3.33); '13, (\$1.12); '15, (\$1.18); '17, (\$1.37); '18, (15¢); '19, (21¢); '20, 25¢; gains (loss) from disc. ops.: '13, 11¢; '14, 57¢; '15, 11¢; '18, 10¢. EPS may not sum due to change in share count. Next earnings report due early May. (B) Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '22: \$951 mill., \$2.49/sh. (D) In mill. (E) Rate base: net orig. cost. Rate all'd on com. eq. in '20: 10.3%; earned on avg. com. eq., '21: 5.4%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	80
Price Growth Persistence	30
Earnings Predictability	10

ENTERGY CORP. NYSE-ETR

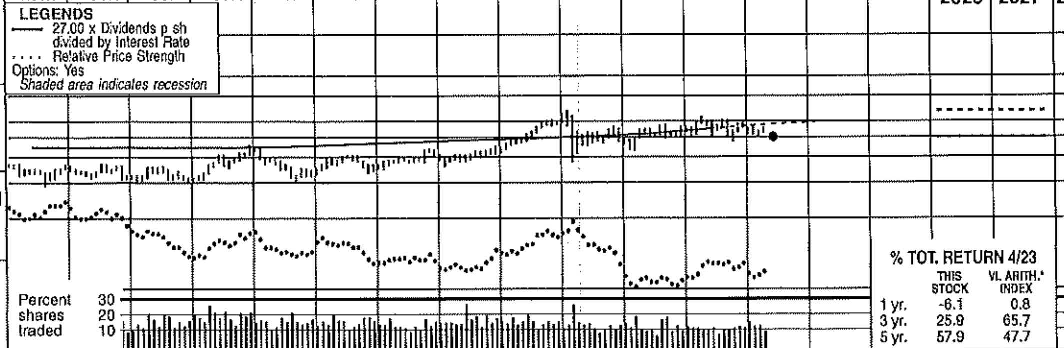
RECENT PRICE 96.80 | P/E RATIO 16.5 (Trailing: 17.6 / Median: 14.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 4 Raised 5/26/23
SAFETY 2 Raised 12/13/19
TECHNICAL 3 Raised 5/26/23
BETA .90 (1.00 = Market)

High:	74.5	72.6	92.0	90.3	82.1	87.9	90.8	122.1	135.5	115.0	126.8	111.9
Low:	61.6	60.2	60.4	61.3	65.4	69.6	71.9	83.2	75.2	85.8	94.9	95.6

Target Price Range 2026 | 2027 | 2028

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



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$88-$150	$119 (25%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	135	(+40%)	12%
Low	100	(+5%)	5%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	348	348	377
to Sell	260	258	274
Hld's(000)	184330	184841	186530

Percent shares traded 30 20 10

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-6.1	0.8
3 yr.	25.9	65.7
5 yr.	57.9	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
59.47	69.15	56.82	64.27	63.67	57.94	63.86	69.71	64.54	60.55	61.35	58.23	54.63	50.51	57.95	65.18	*58.40*	*59.65*	Revenues per sh	*65.20*
11.73	12.89	13.29	16.54	17.53	15.98	16.25	17.68	17.71	18.72	16.70	16.50	17.19	18.21	17.90	15.51	*16.95*	*17.30*	"Cash Flow" per sh	*18.90*
5.60	6.20	6.30	6.66	7.55	6.02	4.96	5.77	5.81	6.88	5.19	5.88	6.30	6.90	6.87	5.37	*5.85*	*6.05*	Earnings per sh A	*6.50*
2.58	3.00	3.00	3.24	3.32	3.32	3.32	3.32	3.34	3.42	3.50	3.58	3.66	3.74	3.86	4.10	*4.30*	*4.45*	Div'd Decl'd per sh B ■ †	*5.00*
10.29	13.92	12.99	13.33	15.21	18.18	15.73	14.82	16.79	17.28	22.07	22.45	21.72	24.52	30.86	25.04	*20.00*	*19.00*	Cap'l Spending per sh	*19.75*
40.71	42.07	45.54	47.53	50.81	51.73	54.00	55.83	51.89	45.12	44.28	46.78	51.34	54.56	57.42	61.40	*63.25*	*65.70*	Book Value per sh C	*73.90*
193.12	189.36	189.12	178.75	176.36	177.81	178.37	179.24	178.39	179.13	180.52	189.06	199.15	200.24	202.65	211.18	*214.00*	*218.00*	Common Shs Outst'g D	*230.00*
19.3	16.6	12.0	11.6	9.1	11.2	13.2	12.9	12.5	10.9	15.0	13.8	16.5	15.3	15.0	21.1	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
1.02	1.00	.80	.74	.57	.71	.74	.68	.63	.57	.75	.75	.88	.79	.81	1.22	*Value Line*		Relative P/E Ratio	*1.00*
2.4%	2.9%	4.0%	4.2%	4.9%	4.9%	5.1%	4.5%	4.6%	4.6%	4.5%	4.4%	3.5%	3.6%	3.7%	3.6%	*estimates*		Avg Ann'l Div'd Yield	*4.3%*

CAPITAL STRUCTURE as of 3/31/23
Total Debt $27589 mill. Due in 5 Yrs $11117 mill.
LT Debt $24464 mill. LT Interest $824.0 mill.
Incl. $54.7 mill. of securitization bonds.
(LT interest earned: 2.8x)
Leases, Uncapitalized Annual rentals $62.1 mill.
Pension Assets-12/22 $6993.1 mill. **Oblig** $8409.6 mill.
Pfd Stock $254.4 mill. **Pfd Div'd** $18.3 mill.
200,000 shs. 6.25%-7.5%, $100 par; 250,000 shs. 8.75%, 1.4 mill. shs. 5.375%; all cum., without sinking fund.
Common Stock 211,446,651 shs. as of 4/28/23
MARKET CAP: $20.5 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
11391	12495	11513	10846	11074	11009	10879	10114	11743	13764	*12500*	*13000*	Revenues ($mill)	*15000*
904.5	1060.0	1061.2	1249.8	950.7	1092.1	1258.2	1406.7	1402.8	1103.2	*1250*	*1320*	Net Profit ($mill)	*1495*
26.7%	37.8%	2.2%	11.3%	1.8%	--	--	--	16.1%	16.1%	*23.0%*	*23.0%*	Income Tax Rate	*23.0%*
10.1%	9.3%	7.4%	8.1%	14.7%	17.5%	16.7%	12.2%	7.1%	2.5%	*8.0%*	*8.0%*	AFUDC % to Net Profit	*7.0%*
55.1%	54.9%	57.8%	63.6%	63.6%	63.2%	62.0%	65.5%	67.6%	64.2%	*64.5%*	*64.5%*	Long-Term Debt Ratio	*64.5%*
43.6%	43.8%	40.8%	35.5%	35.5%	35.9%	37.1%	33.7%	31.7%	35.2%	*35.5%*	*35.5%*	Common Equity Ratio	*35.5%*
22109	22842	22714	22777	22528	24602	27557	32386	36733	36810	*41110*	*43545*	Total Capital ($mill)	*48910*
27882	28723	27824	27921	29664	31974	35183	38853	42244	42477	*45025*	*50590*	Net Plant ($mill)	*56845*
5.4%	6.0%	6.0%	6.9%	5.7%	5.8%	5.9%	5.6%	4.9%	4.3%	*4.5%*	*4.5%*	Return on Total Cap'l	*4.0%*
9.1%	10.3%	11.1%	15.1%	11.6%	12.0%	12.0%	12.6%	11.8%	8.4%	*9.0%*	*9.0%*	Return on Shr. Equity	*8.5%*
9.2%	10.4%	11.2%	15.2%	11.7%	12.2%	12.1%	12.7%	11.9%	8.4%	*9.0%*	*9.0%*	Return on Com Equity E	*8.5%*
3.0%	4.4%	4.8%	7.7%	3.9%	4.9%	5.2%	5.9%	5.2%	1.9%	*2.5%*	*2.5%*	Retained to Com Eq	*2.0%*
68%	58%	58%	50%	68%	61%	58%	55%	57%	78%	*74%*	*74%*	All Div'ds to Net Prof	*77%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-4.1	+3.2	+1.1
Avg. Indust. Use (MWH)	1017	1015	1018
Avg. Indust. Revs. per KWH(¢)	4.95	5.91	7.08
Capacity at Peak (Mw)	25665	NA	NA
Peak Load, Summer (Mw)	21340	NA	NA
Annual Load Factor (%)	62	NA	NA
% Change Customers (yr-end)	+1.0	+1.0	+1.0
Fixed Charge Cov. (%)	202	243	209

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-.5%	-1.5%	2.0%
"Cash Flow"	.5%	-.5%	1.5%
Earnings	-.5%	1.5%	.5%
Dividends	1.5%	2.5%	4.0%
Book Value	1.5%	4.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	2427	2413	2904	2370	10114
2021	2845	2822	3353	2723	11743
2022	2878	3395	4219	3273	13764
2023	2981	*3200*	*3219*	*3100*	*12500*
2024	*3000*	*3400*	*3400*	*3200*	*13000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.59	1.79	2.59	1.93	6.90
2021	1.66	1.30	2.63	1.28	6.87
2022	1.36	.78	2.74	.51	5.37
2023	1.47	*.80*	*2.78*	*.80*	*5.85*
2024	*1.40*	*.95*	*2.85*	*.85*	*6.05*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.91	.91	.91	.93	3.66
2020	.93	.93	.93	.95	3.74
2021	.95	.95	.95	1.01	3.86
2022	1.01	1.01	1.01	1.07	4.10
2023	1.07				

BUSINESS: Entergy Corporation supplies electricity to 3 million customers through subsidiaries in Arkansas, Louisiana, Mississippi, Texas, and New Orleans (regulated separately from Louisiana). Distributes gas to 206,000 customers in Louisiana. Is selling its last nonutility nuclear unit (shut down 5/22). Electric revenue breakdown: residential, 37%; commercial, 24%; industrial, 27%; other, 12%. Generating sources: gas, 68%; nuclear, 22%; coal, 9%; hydro and solar, 1%. Fuel costs: 32% of revenues. '22 reported depreciation rate: 2.7%. Has 11,707 employees. Chairman & CEO: Leo P. Denault. Incorporated: Delaware. Address: 639 Loyola Avenue, P.O. Box 61000, New Orleans, Louisiana 70161. Telephone: 504-576-4000. Internet: www.entergy.com.

Entergy recorded improved first-quarter results. Revenues expanded around 4% year over year to $2.981 billion, aided by higher demand for electricity across its coverage area, including a significant amount of industrial growth in Texas and Louisiana. The company also benefited from greater system reliability. Still, fuel costs rosed quickly, though a lower amount of purchased power partially offset this. Too, Entergy benefited from $76 million in storm securitization income during the quarter. These factors allowed earnings to advance to $1.47 per share.

We expect decent results over the second half of the year. Though revenues face tough comparisons from higher fuel costs last year, operations should benefit from growth in Texas and Louisiana as industrial demand continues to expand. Additionally, we think that the company will continue to capitalize on customers moving into its service territory. Energy has filed for new rates in several locations, which ought to improve net income and allow for better system reliability, as it has spent funds on replacing power lines. These factors will likely enable earnings to advance to $5.85 per share in 2023.

The company should gain from moderate growth over the coming years. Revenues will likely benefit from increasing customers, and Entegy is building a new Orange County station to improve power generation in Texas. Other projects will also help to increase output, while we expect the company to gain from new rate case outcomes in Texas and Louisiana. On the cost side, we think fuel costs will eventually ease as Entergy invests in greener production. It expects to quadruple its output in the renewable space by 2025, should current schedules hold for capital projects. Further expansions could he added if spending plans are approved. Interest costs will likely rise alongside the debt load. So, we foresee earnings advancing to $6.05 per share in 2024 and $6.50 by 2026-2028.

Shares of Entergy are ranked Below Average (4) for Timeliness. This stock also holds subpar 3- to 5-year appreciation potential, but the dividend yield is attractive. All told, this issue is best suited for conservative income-seeking accounts.

John E. Seibert III *June 9, 2023*

(A) Diluted EPS. GAAP starting in 2022. Excl. nonrec. losses: '12, $1.26; '13, $1.14; '14, 56¢; '15, $6.99; '16, $10.14; '17, $2.91; '18, $1.25; '21, $1.33. Next earnings report due early August. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '22: $23.64/sh. (D) In mill. (E) Rate base: Net original cost. Allowed ROE (blended): 9.71%; earned on avg. com. eq., '22: 8.5%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	45
Earnings Predictability	75

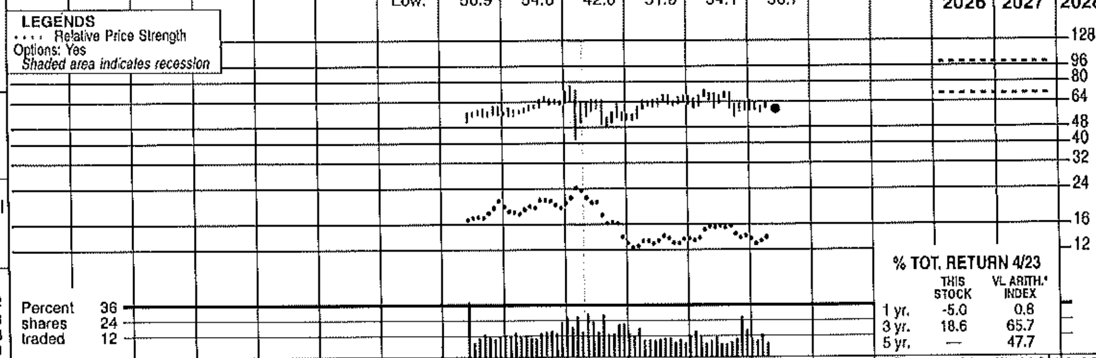
EVERGY, INC. NYSE-EVRG

RECENT PRICE 57.46 | P/E RATIO 15.7 (Trailing: 17.2; Median: NMF) | RELATIVE P/E RATIO 0.96 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 3 Raised 2/3/23
SAFETY 2 New 9/14/18
TECHNICAL 3 Raised 5/26/23
BETA .90 (1.00 = Market)

	2018	2019	2020	2021	2022	2023
High:	61.1	67.8	76.6	69.4	73.1	65.4
Low:	50.9	54.6	42.0	51.9	54.1	56.7

Target Price Range 2026 | 2027 | 2028



18-Month Target Price Range
Low-High $51-$84 Midpoint (% to Mid) $68 (15%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+75%)	18%
Low	70	(+20%)	9%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	304	305	358
to Sell	252	250	268
Hld's(000)	194242	193700	191450

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-5.0	0.8
3 yr.	18.6	65.7
5 yr.	—	47.7

Evergy, Inc. was formed through the merger of Great Plains Energy and Westar Energy in June of 2018. Great Plains Energy holders received .5981 of a share of Evergy for each of their shares, and Westar Energy holders received one share of Evergy for each of their shares. The merger was completed on June 4, 2018. Shares of Evergy began trading on the New York Stock Exchange one day later.

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
--	--	--	--	--	16.75	22.71	21.66	24.36	25.49	25.20	26.10	Revenues per sh	27.40
--	--	--	--	--	4.89	7.18	7.06	8.18	7.34	7.95	8.20	"Cash Flow" per sh	9.20
--	--	--	--	--	2.50	2.79	2.72	3.83	3.26	3.65	3.85	Earnings per sh A	4.85
--	--	--	--	--	1.74	1.93	2.05	2.18	2.33	2.53	2.61	Div'd Decl'd per sh B ■	3.05
--	--	--	--	--	4.19	5.34	6.88	8.60	9.41	9.20	9.25	Cap'l Spending per sh	9.50
--	--	--	--	--	39.28	37.82	38.50	40.32	41.86	42.70	44.10	Book Value per sh C	47.50
--	--	--	--	--	255.33	226.64	226.84	229.30	229.90	230.00	230.00	Common Shs Outst'g D	230.00
--	--	--	--	--	22.7	21.8	21.7	16.2	19.9	Bold figures are		Avg Ann'l P/E Ratio	17.5
--	--	--	--	--	1.23	1.16	1.11	.88	1.15	Value Line		Relative P/E Ratio	.95
--	--	--	--	--	3.1%	3.2%	3.5%	3.5%	4.0%	estimates		Avg Ann'l Div'd Yield	3.7%
--	--	--	--	--	4275.9	5147.8	4913.4	5586.7	5859.1	5800	6000	Revenues ($mill)	6300
--	--	--	--	--	535.8	669.9	618.3	879.7	752.7	840	885	Net Profit ($mill)	1115
--	--	--	--	--	9.8%	12.6%	14.1%	11.7%	5.8%	9.0%	9.0%	Income Tax Rate	9.0%
--	--	--	--	--	2.5%	2.5%	5.5%	5.0%	5.1%	6.0%	6.0%	AFUDC % to Net Profit	5.0%
--	--	--	--	--	40.0%	50.6%	51.3%	50.1%	50.0%	51.5%	51.5%	Long-Term Debt Ratio	53.5%
--	--	--	--	--	60.0%	49.4%	48.7%	49.9%	48.0%	48.5%	48.5%	Common Equity Ratio	46.5%
--	--	--	--	--	16716	17337	17924	18542	19668	20175	21250	Total Capital ($mill)	23400
--	--	--	--	--	18952	19346	20106	21150	22137	23150	24200	Net Plant ($mill)	26300
--	--	--	--	--	4.0%	4.8%	4.5%	5.7%	6.9%	5.5%	5.5%	Return on Total Cap'l	6.0%
--	--	--	--	--	5.3%	7.8%	7.1%	9.5%	8.1%	9.0%	9.0%	Return on Shr. Equity	10.0%
--	--	--	--	--	5.3%	7.8%	7.1%	9.5%	8.1%	9.0%	9.0%	Return on Com Equity E	10.0%
--	--	--	--	--	.6%	2.4%	1.8%	4.1%	3.1%	3.0%	3.0%	Retained to Com Eq	3.5%
--	--	--	--	--	89%	69%	75%	57%	73%	69%	68%	All Div'ds to Net Prof	63%

CAPITAL STRUCTURE as of 3/31/23
Total Debt $10236.6 mill. Due in 5 Yrs $4388.2 mill.
LT Debt $10097.2 mill. LT Interest $305.5 mill.
Incl. $40.9 mill. finance leases.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $18.8 mill.

Pension Assets-12/22 $1714.7 mill.
Oblig $2561.7 mill.

Pfd Stock None

Common Stock 229,680,947 shs.
MARKET CAP: $13.2 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2020	2020	2021
% Change Retail Sales (KWH)	-3.9	+3.1	+6.7
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.14	6.94	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. (%)	286	350	NA

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	--	--	2.5%
"Cash Flow"	--	--	5.0%
Earnings	--	--	7.5%
Dividends	--	--	7.0%
Book Value	--	--	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	1116	1184	1517	1094	4913.4
2021	1611	1236	1616	1122	5586.7
2022	1223	1446	1909	1281	5859.1
2023	1297	1450	1700	1353	5800
2024	1250	1500	1950	1300	6000

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.31	.59	1.60	.22	2.72
2021	.84	.81	1.95	.23	3.83
2022	.53	.84	1.86	.03	3.26
2023	.62	.85	2.00	.18	3.65
2024	.60	.85	2.10	.30	3.85

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.475	.475	.475	.505	1.93
2020	.505	.505	.505	.535	2.05
2021	.535	.535	.535	.5725	2.18
2022	.5725	.5725	.5725	.6125	2.33
2023	.6125				

BUSINESS: Evergy, Inc. was formed through the merger of Great Plains Energy and Westar Energy in June of 2018. Through its subsidiaries (now doing business under the Evergy name), provides electric service to 1.6 million customers in Kansas and Missouri, including the greater Kansas City area. Electric revenue breakdown: residential, 32%; commercial, 27%; industrial, 15%; wholesale, 13%; other, 13%. Generating sources: coal, 54%; nuclear, 17%; purchased, 29%. Fuel costs: 28% of revenues. '22 reported deprec. rate: 3%. Has 4,900 employees. Chairman: Mark A. Ruelle. President & CEO: David A. Campbell. COO: Kevin E. Bryant. Inc.: Missouri. Address: 1200 Main Street, Kansas City, Missouri 64105. Tel.: 816-556-2200. Internet: www.evergy.com.

Evergy's utilities in Kansas have filed general rate cases. The company's Kansas Central utility requested an increase of $204 million, based on a return on equity of 10.25% and a common-equity ratio of 52%. Its Kansas Metro utility filed for a hike of $14 million, based on a 10.25% return on equity and a 52% common-equity ratio. These are the first rate cases Evergy has filed with the Kansas Corporation Commission in five years. New tariffs are expected to take effect in December, and will be too late to have a significant impact on the bottom-line this year.

Our 2023 earnings projection is staying put at $3.65 per share, which is the midpoint of Evergy's updated guidance range of $3.55-$3.75. We think rate relief in Kansas and investments in the company's transmission system will both remain key factors to profit growth over the next few years. Higher transmission margins due to ongoing investments, increased the bottom-line by $0.02 a share in the March period. As a result of the aforementioned factors, we expect earnings to improve in 2024 to $3.85 per share, within Evergy's annual goal of 6%-8% growth from 2021 to 2025, based on the midpoint of managements original 2021 guidance of $3.30.

Evergy recently completed its $250 million acquisition of Persimmon Creek Wind Farm. The purchase will help boost the renewable energy business while eliminating coal-based energy sources, as well as provide an improved grid at low costs to customers. The acquisition is also expected to increase earnings by $0.05 per share and assist the utility in reaching its goal of net-zero carbon emissions by 2045.

Evergy shares have continued to underperform of late. The stock is down more than 5% in value since our March report, and is now down nearly 20% over the past 12 months. Capital appreciation potential to 2026-2028 has improved due to the recent price decline, and return prospects over that interim are solid for a utility. The main attraction here remains the dividend. The yield of 4.4% sits well above the industry average. Evergy also holds a strong potential dividend growth rate of 7.0%.

Zachary J. Hodgkinson *June 9, 2023*

(A) Diluted earnings. Next earnings report due early Aug. (B) Dividends paid in mid-March, June, September, and December. ■ Dividend reinvestment plan available. (C) Incl. intangibles. (D) In millions. (E) Rate base: Original cost depreciated. Rate allowed on common equity in Missouri in '18: none specified; In Kansas in '18: 9.3%; earned on average common equity, '22: 9.8%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	35
Earnings Predictability	85

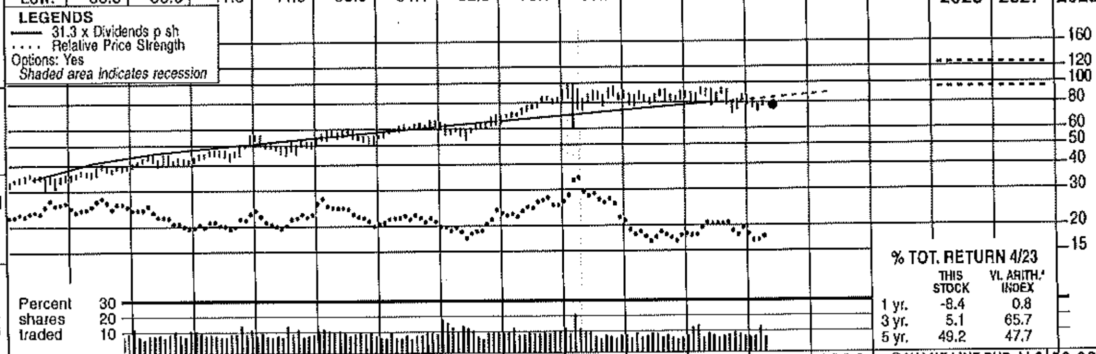
EVERSOURCE ENERGY NYSE-ES

RECENT PRICE 77.72 | P/E RATIO 17.9 (Trailing: 19.0; Median: 19.0) | RELATIVE P/E RATIO 1.07 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 4 Lowered 3/24/23
SAFETY 2 Lowered 5/12/23
TECHNICAL 4 Raised 4/28/23
BETA .90 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	40.9	45.7	56.7	56.8	60.4	66.1	70.5	86.6	99.4	92.7	94.6	86.8
Low:	33.5	38.6	41.3	44.6	50.0	54.1	52.8	63.1	60.7	76.6	70.5	72.5

Target Price Range 2026 | 2027 | 2028



18-Month Target Price Range

Low-High Midpoint (% to Mid)
$69-$128 $99 (25%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	125	(+60%)	15%
Low	95	(+20%)	9%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	411	395	444
to Sell	308	323	316
Hld's(000)	271816	272475	279271

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-8.4	0.8
3 yr.	5.1	65.7
5 yr.	49.2	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB, LLC	26-28
37.27	37.22	30.97	27.76	25.21	19.98	23.16	24.42	25.08	24.11	24.46	26.66	25.85	25.96	28.64	35.27	*36.25*	*38.05*	Revenues per sh	*43.05*
4.82	6.16	4.96	5.68	4.88	4.03	5.22	4.56	4.94	5.46	5.84	6.64	6.65	6.99	7.74	8.79	*9.05*	*9.35*	"Cash Flow" per sh	*10.75*
1.59	1.86	1.91	2.10	2.22	1.89	2.49	2.58	2.76	2.96	3.11	3.25	3.45	3.64	3.86	4.09	*4.35*	*4.65*	Earnings per sh A	*5.60*
.78	.83	.95	1.03	1.10	1.32	1.47	1.57	1.67	1.78	1.90	2.02	2.14	2.27	2.41	2.55	*2.70*	*2.86*	Div'd Decl'd per sh B ■	*3.48*
7.14	8.06	5.17	5.41	6.08	4.69	4.62	5.06	5.44	6.24	7.41	7.96	8.83	8.58	9.22	9.88	*10.50*	*10.10*	Cap'l Spending per sh	*10.00*
18.65	19.38	20.37	21.60	22.65	29.41	30.49	31.47	32.64	33.80	34.99	36.25	38.29	41.01	42.39	44.41	*46.40*	*48.65*	Book Value per sh C	*55.50*
156.22	155.83	175.62	176.45	177.16	314.05	315.27	316.98	317.19	316.89	316.89	316.89	329.88	342.95	344.40	348.44	*351.50*	*355.0*	Common Shs Outst'g D	*360.00*
18.7	13.7	12.0	13.4	15.4	19.9	16.9	17.9	18.1	18.7	19.5	18.7	22.1	23.7	22.2	20.9	**Bold figures are Value Line estimates**		Avg Ann'l P/E Ratio	*19.5*
.99	.82	.80	.85	.97	1.27	.95	.94	.91	.98	.98	1.01	1.18	1.22	1.20	1.21			Relative P/E Ratio	*1.10*
2.6%	3.2%	4.2%	3.6%	3.2%	3.5%	3.5%	3.4%	3.3%	3.2%	3.1%	3.3%	2.8%	2.6%	2.8%	3.0%			Avg Ann'l Div'd Yield	*3.2%*

CAPITAL STRUCTURE as of 12/31/22
Total Debt $22940 mill. Due in 5 Yrs $8012.9 mill.
LT Debt $20134 mill. LT Interest $688.0 mill.
(Total interest coverage: 3.7x)

Leases, Uncapitalized Annual rentals $10.3 mill.

Pension Assets-12/22 $5806.4 mill.
Oblig $5220.1 mill.
Pfd Stock $155.6 mill. Pfd Div'd $7.6 mill.

Common Stock 348,483,425 shs.
as of 1/31/23
MARKET CAP: $27.1 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
7301.2	7741.9	7954.8	7639.1	7752.0	8448.2	8526.5	8904.4	9863.1	12289	*12750*	*13500*	Revenues ($mill)	*15500*
793.7	827.1	886.0	949.8	995.5	1040.5	1121.0	1244.8	1337.7	1427.4	*1535*	*1655*	Net Profit ($mill)	*2030*
35.0%	36.2%	37.9%	36.9%	36.8%	21.7%	19.7%	22.2%	21.9%	24.3%	*24.0%*	*24.0%*	Income Tax Rate	*24.0%*
1.4%	2.4%	2.9%	3.9%	4.7%	6.1%	6.3%	5.3%	4.2%	4.8%	*5.0%*	*5.0%*	AFUDC % to Net Profit	*5.0%*
44.3%	45.9%	45.6%	44.8%	51.2%	52.4%	52.8%	52.4%	54.2%	56.3%	*56.5%*	*56.5%*	Long-Term Debt Ratio	*56.0%*
54.8%	53.2%	53.6%	54.4%	48.2%	46.9%	46.6%	47.1%	45.3%	43.3%	*43.0%*	*43.0%*	Common Equity Ratio	*43.5%*
17544	18738	19313	19697	23018	24474	27097	29842	32233	35763	*37925*	*39950*	Total Capital ($mill)	*45900*
17576	18647	19892	21351	23617	25610	27585	30883	33378	36113	*38725*	*41200*	Net Plant ($mill)	*48000*
5.5%	5.3%	5.5%	5.8%	5.2%	5.2%	5.1%	5.1%	5.1%	5.0%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
8.1%	8.2%	8.4%	8.7%	8.9%	8.9%	8.8%	8.8%	9.1%	9.1%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.0%*
8.2%	8.2%	8.5%	8.8%	8.9%	9.0%	8.8%	8.8%	9.1%	9.2%	*9.5%*	*9.5%*	Return on Com Equity E	*10.0%*
3.4%	3.5%	3.4%	3.5%	3.5%	3.4%	3.6%	3.5%	3.6%	3.6%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
59%	58%	61%	60%	61%	62%	60%	60%	61%	61%	*62%*	*61%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-2.7	+1.6	+.5
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)	+.8	+.6	NA
Fixed Charge Cov. (%)	352	355	317

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	2.0%	4.0%	*6.0%*
"Cash Flow"	5.0%	7.5%	*5.5%*
Earnings	6.5%	5.5%	*6.5%*
Dividends	7.5%	6.0%	*6.5%*
Book Value	5.5%	4.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	2374	1953	2344	2234	8904
2021	2826	2123	2433	2482	9863
2022	3471	2573	3216	3030	12289
2023	*3675*	*2725*	*3250*	*3100*	*12750*
2024	*3900*	*2875*	*3400*	*3325*	*13500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	1.02	.76	1.01	.85	3.64
2021	1.15	.79	1.02	.91	3.86
2022	1.30	.86	1.01	.92	4.09
2023	*1.35*	*.90*	*1.10*	*1.00*	*4.35*
2024	*1.44*	*.97*	*1.17*	*1.07*	*4.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.535	.535	.535	.535	2.14
2020	.5675	.5675	.5675	.5675	2.27
2021	.6025	.6025	.6025	.6025	2.41
2022	.6375	.6375	.6375	.6375	2.55
2023	.675				

BUSINESS: Eversource Energy (formerly Northeast Utilities) is the parent of 12 regulated utilities with 4.4 million electric, natural gas, and water customers. Supplies power to most of Connecticut and gas to part of CT; supplies power to 3/4 of New Hampshire's population; supplies power to western Massachusetts and parts of eastern MA & gas to central & eastern MA; supplies water to CT, MA, & NH. Acq'd NSTAR 4/12; Aquarion 12/17; Columbia Gas 10/20. Electric rev. breakdown: residential, 53%; commercial/indus'l/other, 47%. Fuel costs: 41% of revs. '22 reported depr. rate: 3.6%. Employs 9,626. Chrmn.: James J. Judge. Pres. & CEO: Joseph R. Nolan, Jr. Inc.: MA. Addr.: 300 Cadwell Drive, Springfield, MA 01104. Telephone: 413-785-5871. Internet: www.eversource.com.

Eversource Energy appears to be on track for solid profit gains this year and next. Higher natural gas delivery charges went into effect November 1st, with $32 million to be phased in through October of this year, followed by years of mechanistic increases, tied to inflation and upkeep, on the two-thirds of that figure which apply to Massachusetts. Similarly, higher electric delivery charges went into effect January 1st in that state, with $64 million to be phased in through December of this year, and mechanistic increases based on inflation, maintenance, and transmission & distribution project spending in place thereafter. Although the company's allowable return on equity (ROE) was lowered to 9.8% from 10% in Massachusetts, the nearly real-time formulaic pricing adjustments should go a long ways towards reducing regulatory lag and delivering a reliable stream of revenue growth from that key state territory. Taking the aforementioned figures into account, our full-year 2023 and 2024 share-earnings estimates stand at $4.35 and $4.65, respectively. (First-quarter earnings were reported just after our press cycle.)

The company's 5%-7% long-term earnings and dividend growth targets look achievable. Renewable energy initiatives in the Northeast should drive the company's regulatory capital employed to conservatively expand at a 7%-8% per annum rate for the next several years. Numerous potential "green" energy projects are expected to grow the rate base, including solar, geothermal, and grid modernizations necessary to connect new sources of generation, such as offshore wind.

Eversource shares may be appealing to utility investors with a longer-term leaning. The company has a solid track record of delivering shareholder value, and possesses superior growth prospects relative to its industry peer group. The issue is likely trading at a lower valuation premium than normal, with the dividend yield just 10 basis points above the electric utility median, due to the uncertainty regarding the ongoing strategic review of the offshore wind assets (discussed in detail in our February review). Annual total return potential to 2026-2028 compares favorably to the 8.5% utility median.

Anthony J. Glennon *May 12, 2023*

(A) Diluted EPS. Excl. nonrecur. gain/(losses): '08, (19¢); '10, 9¢; '19, (64¢); '20, (9¢); '21, (32¢); '22, (4¢). Next egs. report due early Aug. Quarterly figures may not sum to full year due to rounding. (B) Div'ds paid late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intangibles. In '22: $25.16/sh. (D) In mill. (E) Rate allowed on com. eq. in MA: (elec.) '22, 9.8%; (gas) '20, 9.7%-9.9%; in CT: (elec.) '18, 9.25%; (gas) '18, 9.3%; in NH: '21, 9.3%; Regulatory Climate: CT, Below Average; NH, Average; MA, Above Average.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	65
Earnings Predictability	100

EXELON CORP. NDQ-EXC

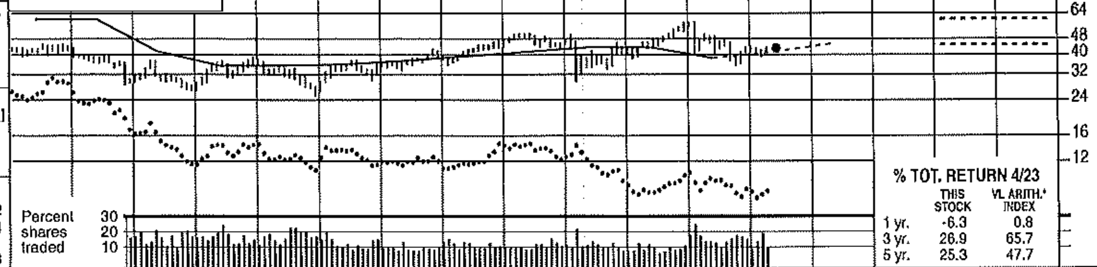
RECENT PRICE 43.18 | P/E RATIO 18.0 (Trailing: 19.1 / Median: 14.0) | RELATIVE P/E RATIO 1.07 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS — Suspended 2/4/22
SAFETY 2 Raised 8/13/21
TECHNICAL — Suspended 2/4/22
BETA NMF (1.00 = Market)

High:	43.7	37.8	38.9	38.3	37.7	42.7	47.4	51.2	50.5	58.0	58.2	44.4
Low:	28.4	26.6	26.5	25.1	26.3	33.3	35.6	43.4	29.3	38.4	35.2	39.0

LEGENDS
— 28.60 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2026 | 2027 | 2028



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$33-$64 $49 (10%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+40%)	12%
Low	45	(+5%)	5%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	508	467	494
to Sell	381	425	421
Hld's(000)	812613	806022	816073

Percent shares traded 30 20 10

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-6.3	0.8
3 yr.	26.9	65.7
5 yr.	25.3	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
28.62	28.65	26.25	28.17	28.53	27.48	29.03	31.90	32.01	33.94	34.81	37.17	35.39	33.85	37.13	19.19	*19.80*	*20.20*	Revenues per sh	*21.50*
7.43	7.64	8.25	8.32	7.23	6.61	6.72	6.61	6.80	7.88	8.37	9.29	9.17	9.65	10.56	6.07	*6.75*	*7.00*	"Cash Flow" per sh	*7.50*
4.03	4.10	4.29	3.87	3.75	1.92	2.31	2.10	2.54	2.68	2.78	3.12	3.22	3.22	2.82	2.26	*2.40*	*2.50*	Earnings per sh A	*3.00*
1.82	2.05	2.10	2.10	2.10	2.10	1.46	1.24	1.24	1.26	1.31	1.38	1.45	1.53	1.53	1.35	*1.44*	*1.60*	Div'd Decl'd per sh B ■	*1.80*
4.05	4.74	4.96	5.03	6.09	6.77	6.29	7.07	8.29	9.26	7.87	7.84	7.45	8.25	8.15	7.19	*6.80*	*6.80*	Cap'l Spending per sh	*7.00*
15.34	16.78	19.16	20.49	21.68	25.07	26.52	26.29	28.04	27.96	30.99	31.77	33.12	33.39	35.13	24.89	*25.20*	*25.20*	Book Value per sh C	*28.75*
660.88	658.15	659.76	661.85	663.37	854.78	857.29	859.83	919.92	924.04	963.34	968.19	973.00	976.00	979.00	994.00	*995.00*	*1000.00*	Common Shs Outst'g D	*1000.0*
18.2	18.0	11.5	11.0	11.3	19.1	13.4	16.0	12.6	12.5	13.4	13.3	14.7	12.4	16.6	19.9	**Bold figures are**		Avg Ann'l P/E Ratio	*17.5*
.97	1.08	.77	.70	.71	1.22	.75	.84	.63	.66	.67	.72	.78	.64	.90	1.15	*Value Line*		Relative P/E Ratio	*.95*
2.5%	2.8%	4.3%	4.9%	5.0%	5.7%	4.7%	3.7%	3.9%	3.7%	3.5%	3.3%	3.1%	3.8%	3.3%	3.2%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 12/31/22
Total Debt $39660 mill. Due in 5 Yrs $12334 mill.
LT Debt $35272 mill. LT Interest $1450 mill.
Includes $390 mill. nonrecourse transition bonds.
(Interest coverage: 2.7x)
Leases, Uncapitalized Annual rentals $156 mill.

Pension Assets-12/21 $20827 mill.
Oblig $23846 mill.
Pfd Stock None

Common Stock 994,126,931 shs.
as of 1/31/23
MARKET CAP: $42.9 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
24888	27429	29447	31360	33531	35985	34438	33039	36347	19078	*19700*	*20200*	Revenues ($mill)	*21500*
1999.0	1826.0	2282.0	2488.0	2636.0	3026.0	3139.0	3149.0	2764.0	2246.4	*2400*	*2500*	Net Profit ($mill)	*3000*
36.5%	27.2%	32.2%	38.5%	34.2%	11.1%	19.4%	17.4%	16.1%	14.5%	*15.0%*	*15.0%*	Income Tax Rate	*15.0%*
4.5%	5.5%	5.4%	8.3%	6.5%	4.6%	5.0%	5.5%	7.4%	7.0%	*6.0%*	*5.0%*	AFUDC % to Net Profit	*5.0%*
44.4%	46.7%	48.3%	55.5%	52.2%	52.8%	49.6%	52.1%	50.9%	59.5%	*61.0%*	*61.0%*	Long-Term Debt Ratio	*64.5%*
55.2%	52.8%	51.3%	44.5%	47.8%	47.2%	50.4%	47.9%	49.1%	40.5%	*39.0%*	*39.0%*	Common Equity Ratio	*35.5%*
41196	42811	50272	58053	62422	65229	63943	68068	70107	58750	*64125*	*64125*	Total Capital ($mill)	*81000*
47330	52087	57439	71555	74202	76707	80233	82584	84219	69076	*69175*	*69175*	Net Plant ($mill)	*77600*
5.9%	5.3%	5.5%	5.5%	5.3%	5.7%	6.0%	5.7%	5.0%	5.0%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
8.7%	8.0%	8.8%	9.6%	8.8%	9.8%	9.7%	9.7%	8.0%	9.5%	*9.5%*	*10.0%*	Return on Shr. Equity	*10.0%*
8.7%	8.0%	8.8%	9.6%	8.8%	9.8%	9.7%	9.7%	8.0%	9.5%	*9.5%*	*10.0%*	Return on Com Equity E	*10.0%*
3.2%	3.3%	4.5%	5.1%	4.7%	5.5%	5.4%	5.1%	3.7%	4.0%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
63%	59%	49%	47%	47%	44%	45%	47%	54%	60%	*60%*	*60%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	NA	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+.6	NA
Fixed Charge Cov. (%)	211	237	325

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	2.5%	1.0%	*NMF*
"Cash Flow"	3.0%	5.5%	*NMF*
Earnings	-0.5%	2.5%	*NMF*
Dividends	-3.0%	4.0%	*NMF*
Book Value	4.5%	3.5%	*NMF*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	8747	7322	8853	8117	33039
2021	9890	7915	8910	9632	36347
2022	5327	4239	4845	4667	19078
2023	*5200*	*4600*	*5400*	*4500*	*19700*
2024	*5300*	*4850*	*5500*	*4550*	*20200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.87	.55	1.04	.76	3.22
2021	d.06	.89	1.09	.90	2.82
2022	.64	.44	.75	.43	2.26
2023	*.65*	*.45*	*.80*	*.50*	*2.40*
2024	*.70*	*.50*	*.80*	*.50*	*2.50*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.3625	.3625	.3625	.3625	1.45
2020	.3825	.3825	.3825	.3825	1.53
2021	.3825	.3825	.3825	.3825	1.53
2022	.3375	.3375	.3375	.3375	1.35
2023	.360				

BUSINESS: Exelon Corporation is a holding company for Commonwealth Edison (ComEd), PECO Energy, Baltimore Gas and Electric (BGE), Pepco, Delmarva Power (DPL), & Atlantic City Electric (ACE). Has 9.1 mill. elec., 1.3 mill. gas customers. Spun off Constellation Energy (nonregulated generating & energy-marketing ops.) 2/22. Acq'd Constellation Energy 3/12; Pepco Holdings 3/16. Elec. rev. breakdown: residntl., 54%; small commercl. & indstrl., 16%; large commercl. & indstrl., 17%; other, 13%. Fuel costs: 48% of revs. '21 deprec. rates: 2.8%-8.7% elec., 2.1% gas. Has 18,700 empls. Chrmn.: John F. Young. CEO: Christopher M. Crane. Inc.: PA. Addr.: 10 S.Dearborn St., P.O. Box 805379, Chicago, IL 60680-5379. Tel.: 312-394-7398. Internet: www.exeloncorp.com.

Exelon looks to be moving in the right direction following the spinoff of its nonutility operations last year. As an entirely regulated utility, the businesses have already started to perform more consistently. Accordingly, management remains committed to its 2021 to 2025 target of 6%-8% annualized earnings growth. Exelon is also introducing its target of 6%-8% profit growth for 2022 through 2026. We think this is achievable, as rate relief and higher distribution rates, as well as an improved macroeconomic environment should expand the company's income over that interim. Our 2023 earnings estimate of $2.40 a share is at the high end of management's targeted range of $2.30-$2.42. (The company was set to report first-quarter results shortly after this Issue went to press.) We are also introducing our 2024 top- and bottom-line targets of $20.2 billion and $2.50 per share, respectively.

The company has a number of pending rate cases. In Illinois, ComEd recently requested a $1.5 billion hike over a four-year stretch. A final order is expected by the end of 2023. In Delaware, Delmarva Power requested an annual electric distribution rate increase of approximately $60 million, indicating a return on equity of 10.5%. Exelon's utilities have remained active in the regulatory arena as of late, and we expect progress in several pending cases. Higher distribution rates should be a key driver of earnings growth moving forward.

Exelon is focused on boosting shareholder value. In late February, the quarterly dividend was raised by 6.7%. Too, management is targeting an approximate 60% dividend payout ratio and expects the dividend to be $1.44 per share this year.

This issue, however, does not stand out at the recent quotation. Conservative, income-oriented accounts may find this stock appealing following a pullback in value. The stock also holds a consistently above-average dividend yield, and is generally considered to be a solid addition to a well-rounded portfolio. Other positives include the 2 (Above Average) Safety rank and the company's strong financial position.

Zachary J. Hodgkinson *May 12, 2023*

(A) Dil. egs. Excl. nonrec. gain (loss): '09, (20¢); '12, (50¢); '13, (31¢); '14, (22¢); '16, ($1.46); '17, $1.19; '18, ($1.05); '19, (21¢); '20, ($1.21); '21, ($1.08); 1Q22, (15¢); disc. ops. gain (loss): '07, 2¢; '08, 3¢. Next egs. report: Aug. (B) Div'ds paid in early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. deferred charges. In '22: $15.20/sh. (D) In mill. (E) Rate allowed on common equity in IL in '15: 9.25%; in MD in '16: 9.75% elec., 9.65% gas; in NJ in '16: 9.75%. Regulatory Climate: PA, NJ: Average; IL, MD: Below Avg.

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

FIRSTENERGY NYSE-FE

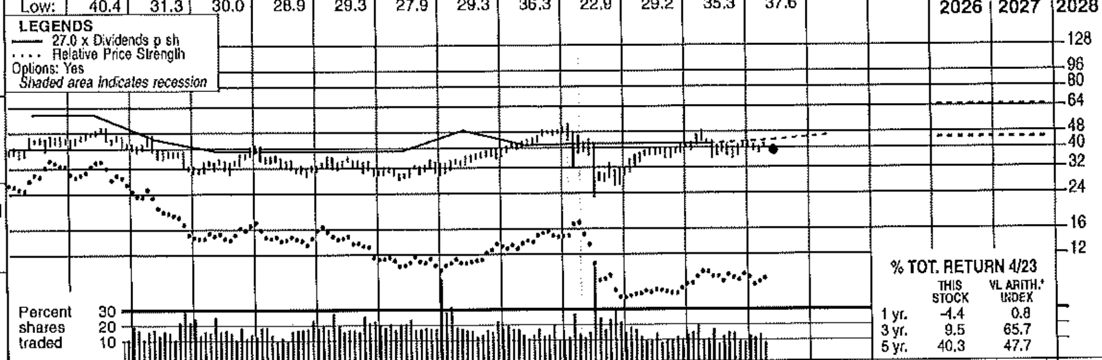
RECENT PRICE 39.01 | P/E RATIO 15.3 (Trailing: 16.1, Median: 13.0) | RELATIVE P/E RATIO 0.91 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 3 Lowered 3/24/23
SAFETY 3 Lowered 7/31/20
TECHNICAL 2 Raised 5/5/23
BETA .85 (1.00 = Market)

High:	51.1	46.8	40.8	41.7	36.6	35.2	39.9	49.1	52.5	41.8	48.8	43.3
Low:	40.4	31.3	30.0	28.9	29.3	27.9	29.3	36.3	22.9	29.2	35.3	37.6

LEGENDS
— 27.0 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2026 | 2027 | 2028



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$33-$54	$44 (10%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+65%)	17%
Low	45	(+15%)	8%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	318	327	379
to Sell	334	296	271
Hld's(000)	469796	470607	462656

Percent shares traded 30 20 10

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.4	0.8
3 yr.	9.5	65.7
5 yr.	40.3	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
42.00	44.70	41.70	43.76	38.87	36.57	35.60	35.74	35.48	32.92	31.49	22.00	20.41	19.87	19.52	21.78	*23.00*	*23.75*	Revenues per sh	*25.65*
8.34	9.04	8.80	8.50	5.75	6.05	6.30	6.26	7.04	7.04	6.54	5.19	4.80	4.59	5.41	4.71	*4.70*	*4.90*	"Cash Flow" per sh	*5.70*
4.22	4.38	3.32	3.25	1.88	2.13	2.97	2.56	2.71	2.63	2.73	2.59	2.56	2.39	2.60	2.41	*2.55*	*2.65*	Earnings per sh A	*3.10*
2.05	2.20	2.20	2.20	2.20	2.20	1.65	1.44	1.44	1.44	1.44	1.82	1.53	1.56	1.56	1.56	*1.62*	*1.72*	Div'd Decl'd per sh B ■	*2.05*
5.36	9.47	7.23	6.44	5.45	7.09	6.90	8.42	6.83	6.93	6.38	5.23	4.93	4.89	4.29	4.82	*5.90*	*6.05*	Cap'l Spending per sh	*6.50*
29.45	27.17	28.08	28.03	31.75	31.29	30.32	29.49	29.33	14.11	8.81	13.17	12.90	13.33	15.21	17.77	*18.80*	*19.85*	Book Value per sh C	*23.25*
304.84	304.84	304.84	304.84	418.22	418.22	418.63	421.10	423.56	442.34	445.33	511.92	540.65	543.12	570.26	572.13	*574.50*	*577.00*	Common Shs Outst'g D	*585.00*
15.6	15.6	13.0	11.7	22.4	21.1	13.1	13.2	12.6	12.7	11.4	13.6	17.1	15.7	14.1	17.0	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.83	.94	.87	.74	1.41	1.34	.74	.69	.63	.67	.57	.73	.91	.81	.76	.99	*Value Line*		Relative P/E Ratio	*1.00*
3.1%	3.2%	5.1%	5.8%	5.2%	4.9%	4.3%	4.3%	4.2%	4.3%	4.6%	5.2%	3.5%	4.2%	4.3%	3.8%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 3/31/23
Total Debt $22726 mill. Due in 5 Yrs $6699 mill.
LT Debt $22124 mill. LT Interest $975 mill.
Incl. $23 mill. finance leases.
(Total interest coverage: 3.1x)
Leases, Uncapitalized Annual rentals $56 mill.

Pension Assets-12/22 $6693 mill. Oblig $8828 mill.

Pfd Stock None

Common Stock 572,836,882 shs.

MARKET CAP: $22.3 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
14903	15049	15029	14562	14022	11261	11035	10790	11132	12459	*13200*	*13700*	Revenues ($mill)	*15000*
1245.0	1074.0	1144.0	1118.0	1213.0	1346.0	1380.0	1296.0	1419.0	1377.0	*1470*	*1535*	Net Profit ($mill)	*1815*
36.1%	28.4%	35.8%	37.4%	37.2%	28.5%	19.8%	13.6%	20.6%	48.1%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
6.0%	11.0%	10.2%	9.2%	6.5%	4.8%	5.1%	5.9%	5.3%	6.1%	*6.0%*	*6.0%*	AFUDC % to Net Profit	*6.0%*
55.5%	60.7%	60.7%	74.5%	84.3%	72.3%	73.8%	75.4%	71.9%	67.6%	*67.0%*	*66.0%*	Long-Term Debt Ratio	*62.0%*
44.5%	39.3%	39.3%	25.5%	15.7%	27.4%	26.2%	24.6%	28.1%	32.4%	*33.0%*	*34.0%*	Common Equity Ratio	*38.0%*
28523	31596	31613	24433	25040	24565	26593	29368	30923	31369	*32850*	*33525*	Total Capital ($mill)	*35700*
33252	35783	37214	29387	28879	29911	31650	33294	34744	36285	*38525*	*39650*	Net Plant ($mill)	*46600*
6.0%	5.0%	5.3%	6.6%	7.0%	7.4%	6.8%	6.0%	6.2%	5.9%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
9.8%	8.6%	9.2%	17.9%	30.9%	19.8%	19.8%	17.9%	16.4%	13.5%	*13.5%*	*13.5%*	Return on Shr. Equity E	*13.5%*
9.8%	8.6%	9.2%	17.9%	30.9%	18.9%	19.7%	17.9%	16.4%	13.5%	*13.5%*	*13.5%*	Return on Com Equity E	*13.5%*
2.6%	3.8%	4.3%	8.1%	14.6%	8.4%	8.1%	6.2%	6.6%	4.8%	*5.0%*	*4.5%*	Retained to Com Eq	*4.5%*
74%	56%	53%	55%	53%	58%	59%	65%	60%	65%	*63%*	*65%*	All Div'ds to Net Prof	*66%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (MWH)	-4.0	+2.4	+1.5
Residential Use (MWH)	54978	55624	55995
Commercial Use (MWH)	34811	35599	36317
Industrial Use (MWH)	52034	54027	55169
Tot. Electric Del'v'd (MWH)	141823	145250	147481
Peak Load Summer (Mw)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.4	+.4
Fixed Charge Cov. (%)	203	171	291

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-6.5%	-9.5%	4.0%
"Cash Flow"	-3.0%	-6.5%	2.5%
Earnings	- -	-1.5%	4.0%
Dividends	-3.5%	1.5%	4.5%
Book Value	-6.5%	-2.5%	7.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	2709	2522	3022	2537	10790
2021	2726	2622	3124	2660	11132
2022	2989	2818	3475	3177	12459
2023	3231	*3075*	*3650*	*3244*	*13200*
2024	*3400*	*3200*	*3775*	*3325*	*13700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.66	.57	.84	.32	2.39
2021	.69	.59	.82	.51	2.60
2022	.60	.53	.79	.50	2.41
2023	.60	*.55*	*.85*	*.55*	*2.55*
2024	*.64*	*.57*	*.87*	*.57*	*2.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.38	.38	.38	.38	1.52
2020	.39	.39	.39	.39	1.56
2021	.39	.39	.39	.39	1.56
2022	.39	.39	.39	.39	1.56
2023	.39				

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 6.214 million customers in OH, PA, NJ, WV, MD, & NY. Acq'd Allegheny Energy 2/11. Electric revenue breakdown: residential, 57.2%; commercial, industrial & other, 42.8%. Purchases most of its power. Power costs: 36.9% of revenues. 2022 reported depreciation rate: 2.7%. Has 12,335 employees. Board Chair, Interim President and CEO: John W. Somerhalder II. Incorporated: Ohio. Address: 76 South Main Street, Akron, Ohio 44308-1890. Telephone: 800-736-3402. Internet: www.firstenergycorp.com.

FirstEnergy has come a long way since the disastrous bribery scandal of a few years ago. Board Chair, Interim President and CEO John Somerhalder and the rest of the top leadership team have done a commendable job of resuscitating the utility holding company after the stock hit rock bottom in mid-2020, and its debt ratings fell to junk status. In 2021, settlements on bribery charges were made with federal prosecutors and Ohio regulators. A growth-oriented plan, still in place, that takes advantage of the company's flexibility and strengths, which comes from its huge Mid-Atlantic and contiguons network, was erected. Investors bought in, and $1 billion in equity was injected in late 2021. In mid-2022, the company completed the sale of a minority interest in its long-range transmission business for $2.38 billion. Fitch upped FirstEnergy's credit rating to investment grade, and other agencies are likely to follow suit now that an additional stake went under contract, to be sold for $3.5 billion, with a closing date due by early 2024. Notably, the company will retain nearly 70% of its overall transmission portfolio.

A permanent chief executive has been appointed by the board of directors. Brian Tierney has been named President and CEO, effective June 1st. Mr. Tierney most recently held a high-level position at the Infrastructure group of Blackstone, the leading global alternative asset management company. He previously spent 23 years at Ohio-based American Electric Power (AEP), one of the largest investor-owned utilities in the U.S., serving as the company's executive vice president of strategy after nearly 12 years as CFO. Mr. Tierney should be able to build upon the positive momentum at FirstEnergy.

The company is set to resume dividend growth later this year. The board increased the payout target to 60%-70% of profits, clearing the way for hikes. The substantial infrastructure investments the company is making, plus forthcoming rate relief, should drive 5%-6% annual earnings and dividend growth to late decade. We think the mix of income, growth and valuation should appeal to most utility investors. Annual total return prospects exceed the peer median by 335 basis points.

Anthony J. Glennon *May 12, 2023*

(A) Dil. EPS. Excl. nonrec. loss: '13, $2.07; '14, $2.05; '15, $1.34; '16, $17.12; '17, $6.61; '18, $1.26; '19, 89¢; '20, 54¢; '21, 33¢; '22, $1.70; 1Q '23, 9¢; gains from disc. ops.: '18, 66¢; '20, 14¢; '21, 8¢. Qtrly. EPS don't sum due to chg. in shs. Next egs. report due July. (B) Div'ds pd. early Mar., June, Sept., & Dec. 3 div'ds in '13, 5 in '18. ■ Div'd reinv. avail. (C) Incl. intang. In '22: $9.88/sh. (D) In mill. (E) High ROE from large writeoffs. Rate base: Depr. orig. cost. Rates all'd on com. eq.: 9.6-11.7%; Reg.: OH, Above Avg.; PA, NJ Avg.; MD, WV Below Avg.

Company's Financial Strength	B+
Stock's Price Stability	80
Price Growth Persistence	30
Earnings Predictability	100

FORTIS INC. TSE-FTS.TO A

RECENT PRICE 57.46 | P/E RATIO 19.8 (Trailing: 19.5 Median: 20.0) | RELATIVE P/E RATIO 1.21 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 3 Raised 4/28/23
SAFETY 2 Raised 7/17/15
TECHNICAL 3 Raised 6/2/23
BETA .70 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$49-$83 $66 (15%)

2026-28 PROJECTIONS

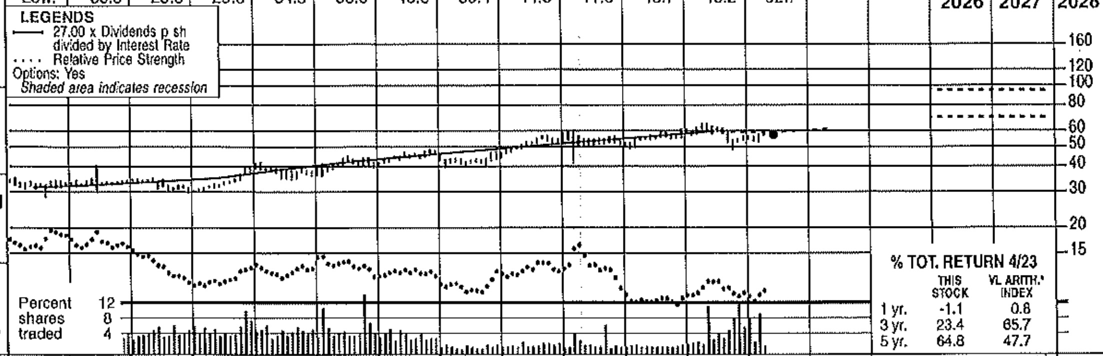
	Price	Gain	Ann'l Total Return
High	95	(+65%)	17%
Low	70	(+20%)	9%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	141	122	134
to Sell	112	134	123
Hld's(000)	236563	238324	240882

High: 40.7 35.1 40.5 42.1 45.1 48.7 47.4 56.9 59.3 61.6 65.4 62.0
Low: 30.5 29.6 29.8 34.5 36.0 40.6 39.4 44.0 41.6 48.7 48.2 52.7

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



Percent shares traded 12 8 4

Target Price Range 2026 | 2027 | 2028

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.1	0.8
3 yr.	23.4	65.7
5 yr.	64.8	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
17.48	23.07	21.24	21.01	19.84	19.07	18.99	19.57	23.89	17.03	19.71	19.58	18.96	19.14	19.90	22.90	21.90	22.85	Revenues per sh	25.10
2.96	3.51	3.66	3.99	3.90	4.10	4.10	3.62	5.21	3.91	5.43	5.40	5.44	5.65	5.76	6.24	6.40	6.60	"Cash Flow" per sh	7.50
1.29	1.52	1.51	1.62	1.74	1.65	1.63	1.38	2.11	1.89	2.66	2.52	2.68	2.60	2.61	2.78	2.90	3.10	Earnings per sh B	3.75
.82	1.00	1.04	1.12	1.17	1.21	1.25	1.30	1.43	1.55	1.65	1.75	1.86	1.97	2.08	2.17	2.29	2.53	Div'd Decl'd per sh C■	2.80
5.16	5.34	5.79	5.89	5.91	5.68	5.32	6.00	7.97	5.13	7.18	7.51	8.03	8.65	7.13	7.02	7.85	8.25	Cap'l Spending per sh	8.25
16.72	18.00	18.57	18.95	20.53	20.84	22.39	24.90	28.63	32.32	31.77	34.80	36.49	36.58	37.21	36.44	39.25	40.50	Book Value per sh D	46.00
155.52	169.19	171.26	174.39	188.83	191.57	213.17	276.00	281.56	401.49	421.10	428.50	463.30	466.80	474.80	482.15	489.00	495.00	Common Shs Outst'g E	510.00
21.1	17.5	16.4	18.2	18.8	20.1	20.0	24.3	18.0	21.6	16.8	17.1	19.2	20.6	21.2	21.1	Bold figures are	Value Line estimates	Avg Ann'l P/E Ratio	21.5
1.12	1.05	1.09	1.16	1.18	1.28	1.12	1.28	.91	1.13	.84	.92	1.02	1.06	1.15	1.22			Relative P/E Ratio	1.20
3.0%	3.8%	4.2%	3.8%	3.6%	3.6%	3.8%	3.9%	3.8%	3.8%	3.7%	4.1%	3.6%	3.7%	3.8%	4.1%			Avg Ann'l Div'd Yield	3.7%

CAPITAL STRUCTURE as of 3/31/23
Total Debt $29189 mill. Due in 5 Yrs $7732 mill.
LT Debt $26466 mill. LT Interest $945 mill.
Incl. $340 mill. finance leases.
(LT interest earned: 2.4x)
Leases, Uncapitalized Annual rentals $8 mill.

Pension Assets-12/22 $3722 mill. Oblig $3922 mill.
Pfd Stock $1623 mill. Pfd Div'd $65 mill.

Common Stock 484,357,731 shs.

MARKET CAP: $27.8 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
4047.0	5401.0	6727.0	6838.0	8301.0	8390.0	8783.0	8935.0	9448.0	11043.0	10700	11300	Revenues ($mill)	12800
390.0	374.0	672.0	660.0	1174.0	1136.0	1238.0	1274.0	1294.0	1340.4	1420	1535	Net Profit ($mill)	1910
7.4%	14.6%	21.3%	16.9%	25.8%	13.4%	12.5%	14.3%	14.3%	16.0%	14.5%	14.5%	Income Tax Rate	14.5%
5.9%	7.2%	7.4%	10.0%	9.5%	8.4%	9.2%	9.3%	9.0%	9.0%	8.0%	8.0%	AFUDC % to Net Profit	7.0%
53.5%	54.8%	53.3%	59.3%	58.4%	58.8%	54.2%	55.6%	55.5%	55.0%	53.5%	53%	Long-Term Debt Ratio	51.5%
37.0%	35.7%	38.1%	36.2%	37.1%	37.2%	41.8%	40.5%	40.8%	41.5%	43.0%	43.5%	Common Equity Ratio	45.0%
12892	19235	21151	35874	36108	40082	40445	42141	43328	44922	46275	48050	Total Capital ($mill)	51900
12267	17816	19595	29337	29668	32654	33988	35998	37816	41663	42250	43500	Net Plant ($mill)	48600
4.6%	3.4%	4.5%	2.8%	4.5%	4.1%	4.4%	4.3%	4.2%	2.4%	4.5%	4.5%	Return on Total Cap'l	5.0%
6.5%	4.3%	6.8%	4.5%	7.8%	6.9%	6.7%	6.8%	6.7%	4.4%	7.0%	7.0%	Return on Shr. Equity	7.5%
7.0%	4.5%	7.4%	4.5%	8.3%	7.2%	6.9%	7.1%	7.0%	4.4%	7.0%	7.0%	Return on Com Equity F	7.5%
3.2%	1.7%	4.5%	2.1%	5.2%	4.1%	4.0%	2.5%	3.5%	3.5%	3.5%	3.5%	Retained to Com Eq	4.0%
61%	68%	46%	59%	41%	46%	45%	67%	52%	78%	81%	82%	All Div'ds to Net Prof G	75%

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	NA	NA	NA
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 (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	207	211	215

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	--	-.5%	3.5%
"Cash Flow"	3.5%	3.5%	5.0%
Earnings	4.5%	3.5%	5.0%
Dividends	5.5%	5.5%	6.0%
Book Value	6.5%	3.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	2391	2077	2121	2346	8935
2021	2539	2130	2196	2583	9448
2022	2835	2487	2553	3168	11043
2023	3319	2450	2381	2550	10700
2024	3000	2500	2550	3250	11300

Cal-endar	EARNINGS PER SHARE B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.67	.59	.63	.71	2.60
2021	.76	.54	.62	.69	2.61
2022	.74	.59	.68	.77	2.78
2023	.90	.60	.65	.75	2.90
2024	.80	.65	.80	.85	3.10

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.45	.45	.45	.4775	1.83
2020	.4775	.4775	.4775	.505	1.94
2021	.505	.505	.505	.535	2.05
2022	.535	.535	.535	.565	2.17
2023	.565				

BUSINESS: Fortis Inc.'s main focus is electricity, hydroelectric, and gas utility operations (both regulated and nonregulated) in the United States, Canada, and the Caribbean. Has 2 mill. electric, 1.3 mill. gas customers. Owns UNS Energy (Arizona), Central Hudson (New York), FortisBC Energy (British Columbia), FortisAlberta (Central Alberta), and Eastern Canada (Newfoundland). Sold commercial real estate and hotel property assets in 2015. Acquired ITC Holdings 10/16. Fuel costs: 31% of revs. '22 reported deprec. rate: 2.6%. Has 9,100 employees. Chairman: Douglas J. Haughey. President & CEO: David G. Hutchens. Inc.: Canada. Address: Fortis Place, Suite 1100, 5 Springdale St., PO Box 8837, St. John's, NL, Canada, A1B 3T2. Tel.: 709-737-2800. Internet: www.fortisinc.com.

We think that Fortis will post steady earnings growth this year and next. The company's $22.3 billion five-year capital plan is expected to rise to over $46 billion by 2027 due to rate base increases. Rate relief will likely remain a key driver of growth and help improve upon low allowed returns, seen in many of Fortis utilities. There are currently ongoing cases in British Columbia and Arizona, and decisions in both are expected shortly. Too, in British Columbia, Fortis BC received approval to invest a record high $155 million into energy efficiency programs.

Our 2023 bottom-line projection is staying put at $2.90 per share. Along with rate relief, the Inflation Reduction Act will benefit earnings growth and help the transition to clean energy over the next few years. As a reminder, the new five-year capital plan includes $5.9 billion in cleaner energy investments. Fortis also has strong Price Stability and Earnings Predictability ratings, as well as a stretch of strong financial performances of late. We expect that the aforementioned factors will remain next year, and look for full-year earnings of $3.10 per share.

The utility remains committed to its target of 4%-6% annual dividend growth through 2027. The company has a proven track record of dividend growth, and the distribution has been raised in 49 consecutive years. We think the Board of Directors will raise the quarterly disbursement by 6% at the third-quarter meeting in September.

Fortis stock has outperformed nearly all the electric utility equities over the past six months. The stock is up more than 25% over that interim, largely due to better-than-expected financial results of late. As a reminder, the company also joined the S&P Small Cap 600 Index in February. Income-oriented investors likely will be drawn to the dividend yield of 4.0%, which sits well above the industry average and remains this issue's most notable feature. Meanwhile, total return potential for the 18-month and 3-to 5-year periods is solid for a utility. Indeed, the midpoint of our 18-month Target Price Range represents a 25% premium to the current quotation, which is above the *Value Line* median.

Zachary J. Hodgkinson *June 9, 2023*

(A) Also trades on NYSE (FTS). All data in Canadian $. (B) Dil. egs. Excl. nonrecur. gains (loss): '07, 3¢; '14, 2¢; '15, 48¢; '17, (35¢); '18, 7¢. '19, $1.12. '19 EPS don't sum due to chng. in shs. Next egs. report due early Aug. (C) Div'ds histor. pd. early Mar., June, Sept., and Dec. ■ Div'd reinv. plan avail. (2% disc.). (D) Incl. intang. In '22: $34.05/sh. (E) In mill. (F) Rates all'd on com. eq.: 8.3%-10.32%; earn. on avg. com. eq., '21: 7.1%. Reg. Clim.: FERC, Above Avg.; AZ, Below Avg.; NY, Below Avg. (G) Excl. div'ds pd. via reinv. plan.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	95

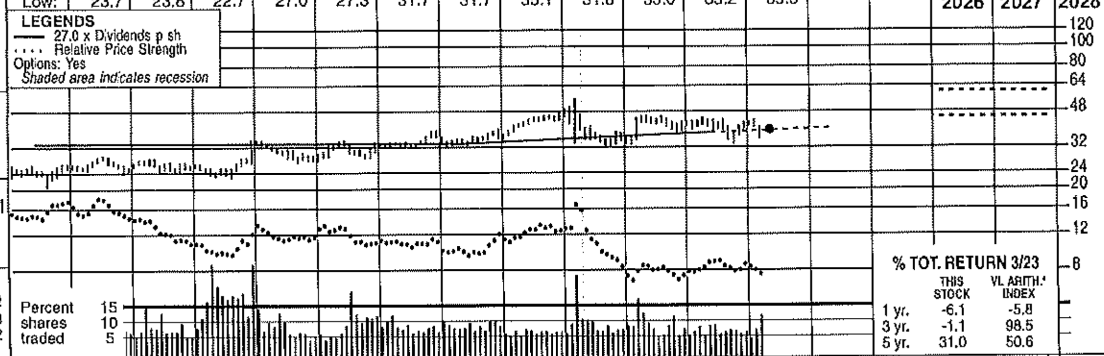
HAWAIIAN ELECTRIC NYSE-HE

RECENT PRICE 39.02 | P/E RATIO 17.2 (Trailing: 17.7 / Median: 19.0) | RELATIVE P/E RATIO 0.99 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 3 Raised 1/27/23
SAFETY 2 Raised 11/2/12
TECHNICAL 4 Lowered 4/21/23
BETA .85 (1.00 = Market)

High:	29.2	28.3	35.0	34.9	35.0	38.7	39.3	47.6	55.2	46.0	44.7	43.7	
Low:	23.7	23.8	22.7	27.0	27.3	31.7	31.7	35.1	31.8	33.0	33.2	35.3	

Target Price Range 2026 | 2027 | 2028



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$35-$57	$46 (20%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+55%)	14%
Low	45	(+15%)	7%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	166	141	163
to Sell	117	147	132
Hld's(000)	58364	58730	60941

% TOT. RETURN 3/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-6.1	-5.8
3 yr.	-1.1	98.5
5 yr.	31.0	50.6

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
30.40	35.56	24.98	28.14	33.76	34.46	31.98	31.59	24.22	21.92	23.49	26.28	26.38	23.63	26.08	34.18	*31.40*	*32.15*	Revenues per sh	*35.95*
3.01	2.72	2.59	2.88	3.18	3.28	3.22	3.41	3.31	4.17	3.68	4.20	4.55	4.48	4.80	4.90	*5.05*	*5.30*	"Cash Flow" per sh	*6.20*
1.11	1.07	.91	1.21	1.44	1.67	1.62	1.64	1.50	2.29	1.64	1.85	1.99	1.81	2.25	2.20	*2.30*	*2.40*	Earnings per sh A	*3.00*
1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.28	1.32	1.36	1.40	*1.44*	*1.48*	Div'd Decl'd per sh B ■	*1.64*
2.62	3.12	3.29	1.92	2.45	3.32	3.49	3.31	3.39	3.04	4.55	4.94	4.20	3.52	2.88	3.14	*3.35*	*3.55*	Cap'l Spending per sh	*4.20*
15.29	15.35	15.58	15.67	15.95	16.28	17.06	17.47	17.94	19.03	19.28	19.86	20.93	21.41	21.87	20.12	*21.70*	*22.55*	Book Value per sh C	*28.05*
83.43	90.52	92.52	94.69	96.04	97.93	101.26	102.57	107.46	108.58	108.79	108.88	108.97	109.18	109.31	109.47	*110.50*	*111.00*	Common Shs Outst'g D	*114.00*
21.6	23.2	19.8	18.6	17.1	15.8	16.2	15.9	20.4	13.6	20.7	18.9	21.3	21.5	18.2	18.5	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
1.15	1.40	1.32	1.18	1.07	1.01	.91	.84	1.03	.71	1.04	1.02	1.13	1.10	.98	1.08	*Value Line*		Relative P/E Ratio	*.95*
5.2%	5.0%	6.9%	5.5%	5.0%	4.7%	4.7%	4.8%	4.1%	4.0%	3.7%	3.5%	3.0%	3.4%	3.3%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*3.1%*

CAPITAL STRUCTURE as of 12/31/22
Total Debt $2645.9 mill. **Due in 5 Yrs** $545.0 mill.
LT Debt $2385.0 mill. **LT Interest** $105.0 mill.
Incl. $50 mill. 6.5% oblig. pfd. sec. of trust subsid.
(LT interest earned: 3.9x)
Leases, Uncapitalized Annual rentals $11.2 mill.
Pension Assets-12/22 $1806.4 mill.
Oblig $1856.4 mill.
Pfd Stock $34.3 mill. **Pfd Div'd** $1.9 mill.
1,114,657 shs. 4¼% to 5¼%, $20 par. call. $20 to $21; 120,000 shs. 7⅝%, $100 par. call. $100.
Sinking fund ended 2018.
Common Stock 109,472,304 shs. as of 2/15/23
MARKET CAP: $4.3 billion (Mid Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
3238.5	3239.5	2603.0	2380.7	2555.6	2860.8	2874.6	2579.8	2850.4	3742.0	*3470*	*3570*	Revenues ($mill)	*4100*
163.4	170.2	161.8	250.1	180.6	203.7	219.8	199.7	248.1	243.0	*255*	*265*	Net Profit ($mill)	*340*
34.0%	35.0%	36.5%	33.1%	34.7%	20.0%	19.0%	17.0%	20.2%	20.1%	*19.0%*	*19.0%*	Income Tax Rate	*19.0%*
4.8%	5.5%	5.8%	4.6%	9.6%	7.7%	7.5%	5.9%	5.2%	5.2%	*7.0%*	*7.0%*	AFUDC % to Net Profit	*6.0%*
44.0%	45.2%	43.5%	41.6%	43.4%	47.5%	44.6%	46.5%	46.4%	51.6%	*51.5%*	*51.0%*	Long-Term Debt Ratio	*50.0%*
55.0%	53.8%	55.5%	57.5%	55.7%	51.7%	54.6%	52.7%	52.8%	47.7%	*47.5%*	*48.0%*	Common Equity Ratio	*49.5%*
3142.9	3332.3	3473.5	3595.1	3765.5	4182.3	4176.9	4435.9	4524.1	4621.8	*4900*	*5100*	Total Capital ($mill)	*5900*
3858.9	4148.8	4377.7	4603.5	5025.9	4830.1	5109.6	5265.7	5392.1	5687.0	*5775*	*5900*	Net Plant ($mill)	*6200*
6.4%	6.2%	5.7%	7.9%	5.8%	5.9%	6.3%	5.5%	6.4%	6.4%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
9.3%	9.3%	8.2%	11.9%	8.5%	9.3%	9.5%	8.4%	10.2%	10.9%	*12.5%*	*12.5%*	Return on Shr. Equity	*12.0%*
9.4%	9.4%	8.3%	12.0%	8.5%	9.3%	9.6%	8.5%	10.3%	10.9%	*12.5%*	*12.5%*	Return on Com Equity E	*12.0%*
3.7%	2.3%	1.5%	6.3%	2.1%	3.1%	3.4%	2.3%	4.1%	4.0%	*5.5%*	*6.0%*	Retained to Com Eq	*6.0%*
61%	75%	83%	48%	76%	67%	64%	73%	61%	64%	*63%*	*62%*	All Div'ds to Net Prof F	*62%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	NA	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	24.21	26.88	36.75
Capacity at Yearend (Mw)	2254	2278	2100
Peak Load, Winter (Mw)	1471	1471	1467
Annual Load Factor (%)	66.2	67.2	68.2
% Change Customers (yr-end)	+.6	+.5	-.2
Fixed Charge Cov. (%)	337	393	356

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-1.5%	4.0%	*4.5%*
"Cash Flow"	4.5%	5.0%	*4.5%*
Earnings	4.0%	3.0%	*6.0%*
Dividends	1.0%	2.0%	*3.0%*
Book Value	3.0%	2.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	677.2	609.0	641.4	652.2	2579.8
2021	642.9	680.3	756.9	770.3	2850.4
2022	785.1	895.6	1042	1019	3742.0
2023	*755*	*830*	*950*	*935*	*3470*
2024	*770*	*855*	*975*	*960*	*3570*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.31	.45	.59	.46	1.81
2021	.59	.58	.58	.50	2.25
2022	.63	.48	.57	.52	2.20
2023	*.50*	*.60*	*.65*	*.55*	*2.30*
2024	*.50*	*.65*	*.70*	*.55*	*2.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.32	.32	.32	.32	1.28
2020	.33	.33	.33	.33	1.32
2021	.34	.34	.34	.34	1.36
2022	.35	.35	.35	.35	1.40
2023	.36				

BUSINESS: Hawaiian Electric Industries, Inc. is the parent company of Hawaiian Electric Company, Inc. (HECO), American Savings Bank (ASB), and Pacific Current. HECO & its subs., Maui Electric Co. (MECO) & Hawaii Electric Light Co. (HELCO), supply electricity to 469,668 customers on Oahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Elec. rev. breakdown: residential, 44%; commercial, 19%; industrial, 37%; other, less than 1%. Generating sources: oil, 52%; purch., 48%. Fuel costs: 50%+ of revs. '22 reported deprec. rate: 3.3%. Has 3,756 employees. Chairman: Tom Fargo. Pres. & CEO: Scott Seu. Inc.: HI. Address: 1001 Bishop St., Suite 2900, Honolulu, HI 96808-0730. Telephone: 808-543-5662. Internet: www.hei.com.

Hawaiian Electric should grow its earnings by about 5% this year and the next. The new regulatory construct of Performance Based Regulation will be a good thing for HE. Last year, the bottom line was hit hard by inflation and high oil prices, but we do not expect as harmful an impact going forward. Numerous solar projects are underway, which should help with many line items on the cost ledger. Moreover, the banking arm is poised for a solid run. Loans increased by 15% in 2022, the strongest growth figure in over a decade. Too, underlying operating metrics are all looking good. Most notably, net interest income has been rising. All told, we think per-share profits should reach $2.30 in 2023, followed by an incline to $2.40 the following year.

The 2022-2023 Sustainability Report detailed the progress the company is making in the renewable energy field. At the end of 2022, 37% of single-family homes in the island chain had rooftop solar. Also, Oahu's grid-scale solar and storage project is online, and the last coal plant in the state has now been shuttered. Digging deeper, 91% of new rooftop solar installations included battery storage. These are all welcome signs, as Hawaii has struggled to get projects up and running in the COVID years. Financial, regulatory, legal, and supply-chain challenges have been the primary culprits.

The dividend continues its pattern that has been in place since 2019. HE paid an annual stipend of $1.24 ($0.31 a quarter) for many years. Then, in 2019 it was upped by a penny per quarter ($0.04 per annum). Since then, each year has followed suit, including this year, which has begun with a payout of $0.36 for the first quarter (up 2.85%).

There is not much to get excited about with these shares at this time. The stock has a neutral designation for relative price performance in the year ahead. For the 18-month window, the reading is below average versus the equities in our coverage universe. Capital appreciation potential for the pull to 2026-2028 is subpar. On top of this, the yield is just on par with the average utility. More appealing options are present elsewhere in the electric utilities industry.

Erik M. Manning *April 21, 2023*

(A) Diluted EPS. Excl. nonrec. losses: '07, 9¢; '12, 25¢; '17, 12¢. EPS don't sum due to rounding. Next earnings report due early May. (B) Div'ds paid early March, June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. deferred cahrges. In '22: $272.4 mill., $2.49/sh. (D) In mill., adj. for split. (E) Rate base: Orig. cost. Rate allowed on com. eq. in '18: HECO, 9.5%; in '18: HELCO, 9.5%; in '18: MECO, 9.5%; earned on avg. com. eq., '21: 10.4%. Regulat. Climate: Below Avg. (F) Excl. div'ds paid through reinv. plan.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	50
Earnings Predictability	80

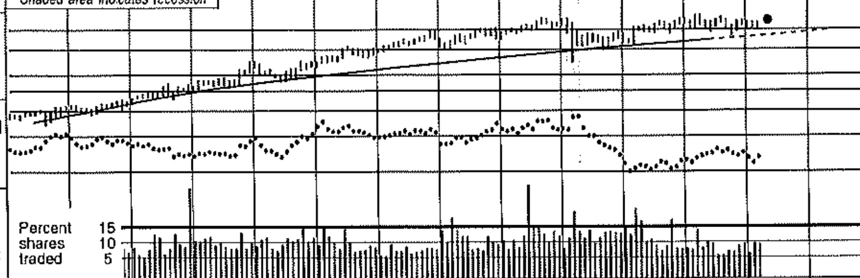
IDACORP, INC. NYSE-IDA

RECENT PRICE 111.42 | P/E RATIO 22.2 (Trailing: 21.8 / Median: 20.0) | RELATIVE P/E RATIO 1.28 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 4 Lowered 3/24/23
SAFETY 1 Raised 1/22/21
TECHNICAL 5 Lowered 3/24/23
BETA .80 (1.00 = Market)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	45.7	54.7	70.1	70.5	83.4	100.0	102.4	114.0	113.6	113.8	118.9	111.5
Low:	38.2	43.1	50.2	55.4	65.0	77.5	79.6	89.3	69.1	85.3	93.5	99.4

LEGENDS
— 29.4 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2026 | 2027 | 2028
200, 160, 100, 80, 60, 50, 40, 30, 20

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$88-$146 $117 (5%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	135	(+20%)	8%
Low	110	(Nil)	3%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	174	159	187
to Sell	164	155	162
Hld's(000)	40518	40715	41351

Percent shares traded 15 10 5

% TOT. RETURN 3/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-3.3	-5.8
3 yr.	34.7	98.5
5 yr.	40.0	50.6

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
19.51	20.47	21.92	20.97	20.55	21.55	24.81	25.51	25.23	25.04	26.76	27.19	26.70	26.77	28.86	32.51	*29.40*	*30.50*	Revenues per sh	*34.80*
4.11	4.27	5.07	5.35	5.84	5.93	6.29	6.58	6.70	6.86	7.50	7.85	8.07	8.19	8.41	8.55	*8.75*	*9.30*	"Cash Flow" per sh	*10.65*
1.86	2.18	2.64	2.95	3.30	3.37	3.64	3.85	3.87	3.94	4.21	4.49	4.61	4.69	4.85	5.11	*5.10*	*5.40*	Earnings per sh A	*6.30*
1.20	1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.92	2.08	2.24	2.40	2.56	2.72	2.88	3.04	*3.20*	*3.40*	Div'd Decl'd per sh B ■ †	*4.15*
6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.45	5.84	5.89	5.66	5.51	5.53	6.16	5.94	8.56	*14.00*	*16.00*	Cap'l Spending per sh	*11.00*
26.79	27.76	29.17	31.01	33.19	35.07	36.84	38.85	40.88	42.74	44.65	47.01	48.88	50.73	52.82	55.52	*57.85*	*60.20*	Book Value per sh C	*67.00*
45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.27	50.34	50.40	50.42	50.42	50.42	50.46	50.52	50.56	*51.00*	*51.50*	Common Shs Outst'g D	*53.00*
18.2	13.9	10.2	11.8	11.5	12.4	13.4	14.7	16.2	19.1	20.6	20.5	22.3	19.9	20.8	21.0	*Bold figures are*		Avg Ann'l P/E Ratio	*19.5*
.97	.84	.68	.75	.72	.79	.75	.77	.82	1.00	1.04	1.11	1.19	1.02	1.12	1.22	*Value Line*		Relative P/E Ratio	*1.10*
3.5%	4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%	3.1%	2.8%	2.6%	2.6%	2.5%	2.9%	2.9%	2.8%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 12/31/22
Total Debt $2194.1 mill. Due in 5 Yrs $335.0 mill.
LT Debt $2194.1 mill. LT Interest $110.0 mill.
(LT interest earned: 4.4x)

Pension Assets-12/22 $839.7 mill.
Oblig $953.8 mill.

Pfd Stock None

Common Stock 50,570,167 shs.
as of 2/10/23

MARKET CAP: $5.6 billion (Mid Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
1246.2	1282.5	1270.3	1262.0	1349.5	1370.8	1346.4	1350.7	1458.1	1644.0	*1500*	*1570*	Revenues ($mill)	*1845*
182.4	193.5	194.7	198.3	212.4	226.8	232.9	237.4	245.6	259.0	*260*	*280*	Net Profit ($mill)	*335*
28.3%	8.0%	19.0%	15.5%	18.6%	7.1%	9.5%	10.8%	13.1%	12.7%	*13.0%*	*13.0%*	Income Tax Rate	*13.0%*
12.3%	13.6%	16.3%	16.3%	13.9%	15.2%	16.2%	17.3%	17.7%	.6%	*15.0%*	*15.0%*	AFUDC % to Net Profit	*16.0%*
46.6%	45.3%	45.6%	44.8%	43.7%	43.6%	41.3%	43.9%	42.8%	43.9%	*46.5%*	*47.0%*	Long-Term Debt Ratio	*50.0%*
53.4%	54.7%	54.4%	55.2%	56.3%	56.4%	58.7%	56.1%	57.2%	56.1%	*53.5%*	*53.0%*	Common Equity Ratio	*50.0%*
3465.9	3567.6	3783.3	3898.5	3997.5	4205.1	4201.3	4560.4	4669.1	5001.4	*5425*	*5800*	Total Capital ($mill)	*7000*
3665.0	3833.5	3992.4	4172.0	4283.9	4395.7	4531.5	4709.5	4901.8	5173.0	*5650*	*6000*	Net Plant ($mill)	*7000*
6.4%	6.6%	6.2%	6.1%	6.3%	6.4%	6.5%	6.1%	6.2%	6.1%	*6.0%*	*6.0%*	Return on Total Cap'l	*5.5%*
9.9%	9.9%	9.5%	9.2%	9.4%	9.6%	9.4%	9.3%	9.2%	9.2%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
9.9%	9.9%	9.5%	9.2%	9.4%	9.6%	9.4%	9.3%	9.2%	9.2%	*9.0%*	*9.0%*	Return on Com Equity E	*9.5%*
5.6%	5.4%	4.8%	4.3%	4.4%	4.4%	4.2%	3.9%	3.7%	3.7%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
43%	46%	50%	53%	53%	54%	56%	58%	60%	60%	*63%*	*63%*	All Div'ds to Net Prof	*66%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	+2.0	+3.9	+7.3
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)	3392	3751	3568
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+2.7	+2.8	+2.4
Fixed Charge Cov. (%)	313	334	419

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	3.5%	2.5%	*3.0%*
"Cash Flow"	4.0%	3.5%	*4.0%*
Earnings	4.0%	4.0%	*4.5%*
Dividends	8.5%	6.5%	*6.5%*
Book Value	5.0%	4.5%	*4.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	291.0	318.8	425.3	315.6	1350.7
2021	316.1	360.1	446.9	335.0	1458.1
2022	344.3	358.7	518.0	422.9	1644.0
2023	*295*	*335*	*500*	*370*	*1500*
2024	*310*	*350*	*520*	*390*	*1570*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.74	1.19	2.02	.74	4.69
2021	.89	1.38	1.93	.65	4.85
2022	.91	1.27	2.10	.83	5.11
2023	*.90*	*1.30*	*2.00*	*.90*	*5.10*
2024	*.95*	*1.35*	*2.10*	*1.00*	*5.40*

Calendar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.63	.63	.63	.67	2.56
2020	.67	.67	.67	.71	2.72
2021	.71	.71	.71	.75	2.88
2022	.75	.75	.75	.79	3.04
2023	.79				

BUSINESS: IDACORP, Inc. is a holding company for Idaho Power Company, a regulated electric utility that serves 618,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon (population: 1.4 million). Most of the company's revenues are derived from the Idaho portion of its service area. Revenue breakdown: residential, 38%; commercial, 27%; industrial, 22%; irrigation, 12%; other, 1%. Generating sources: hydro, 29%; coal, 20%; gas, 13%; purchased, 39%. Fuel costs: 40% of revenues. '22 reported depreciation rate: 3.0%. Has 2,077 employees. Chairman: Richard J. Dahl. President & CEO: Lisa Grow. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, Idaho 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

IDACORP's streak of annual earnings growth will be tested this year. Management has provided an earnings outlook of $4.95 to $5.15 a share, which gives some hope that there will be a year-over-year gain. However, we are placing our figure at $5.10, given the elevated capital expenditures that IDA will be laying out in 2023. The company's system is stressed, and new capacity resources are entering the pipeline and they do not come cheap. Population growth in its service area, now up to 1.4 million, has been stout in the last decade, and when weather conditions deem necessary (summer, irrigation season) the peaks get elevated. All this pressure comes at a time when inflation is still well higher than usual and the interest on borrowings is more punishing to the bottom line. Next year, we look for a handsome earnings advance, to around $5.40 per share, as macroeconomic troubles dissipate and rate relief should be in the cards. Subscribers should note that capital expenditures will be even higher next year, with the forecasts then coming down a bit out to decade's end.

Rate cases are coming in both Idaho and Oregon. IDACORP has not filed a general rate case since 2011. In that time frame, the population/customer growth has been sizable, and the investments made to meet capacity needs have been large ones. With that, we think regulators will have to play ball with this utility. No particulars have been disclosed as of this writing, but the belief is that the Idaho filing will come by June 1st of this year, with the Oregon filing occurring in 2024. Processing wise, leadership has set the time after the filing to when higher rates will actually be in effect, which is seven months in Idaho and 10 months in Oregon.

IDACORP's stock is high quality (Safety: 1), but lacks investment appeal trading around the $110 mark. Our Timeliness Ranking System has IDA pegged as a 4 (Below Average), meaning we think it will lag the broader market averages in the year ahead. Add to this, appreciation potential in the next 18 months, and three to five years hence, is subpar. Further, the three-digit quotation brings the yield to below 3%, so income-minded accounts have nothing to see here.

Erik M. Manning *April 21, 2023*

(A) Diluted EPS. Earnings may not sum due to rounding. Next earnings report due early May. (B) Dividends historically paid in late February, May, August, and November. ■ Dividend reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '22: $1421.9 mill., $28.12/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on common equity in '12: 10% (imputed); earned on avg. common equity, '21: 9.4%. Regulatory Climate: Above Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	100

NEXTERA ENERGY NYSE-NEE

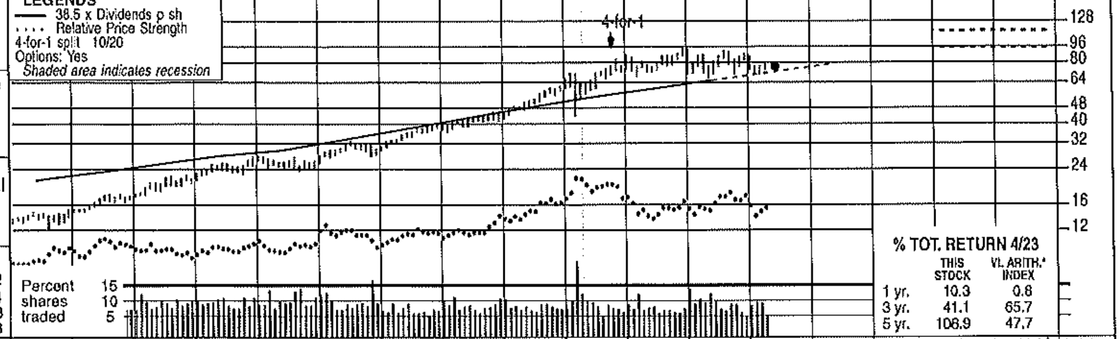
RECENT PRICE 76.80 | P/E RATIO 24.4 (Trailing: 25.5, Median: 23.0) | RELATIVE P/E RATIO 1.45 | DIV'D YLD 2.5% | VALUE LINE

TIMELINESS 3 Raised 5/5/23
SAFETY 1 Raised 2/16/18
TECHNICAL 4 Raised 5/5/23
BETA .95 (1.00 = Market)

High:	18.1	22.4	27.7	28.2	33.0	39.8	46.1	61.3	83.3	93.7	93.6	86.5	
Low:	14.6	17.5	21.0	23.4	25.5	29.3	36.3	42.2	43.7	68.3	67.2	69.6	

Target Price Range 2026 | 2027 | 2028

LEGENDS
— 38.5 x Dividends p sh
.... Relative Price Strength
4-for-1 split 10/20
Options: Yes
Shaded area indicates recession



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$63-$131 $97 (25%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	115	(+50%)	13%
Low	95	(+25%)	8%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	1104	1061	1244
to Sell	949	945	928
Hld's(000)	1514051	1525741	1566738

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	10.3	0.8
3 yr.	41.1	65.7
5 yr.	106.9	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
9.37	10.03	9.45	9.10	9.22	8.41	8.70	9.61	9.48	8.63	9.13	8.75	9.82	9.18	8.70	10.55	13.35	14.55	Revenues per sh	18.00
1.71	2.01	2.19	2.41	2.32	2.17	2.63	3.03	3.23	3.24	3.03	3.84	4.22	4.52	4.70	5.30	5.60	5.95	"Cash Flow" per sh	7.25
.82	1.02	.99	1.19	1.21	1.14	1.21	1.40	1.52	1.45	1.63	1.67	1.94	2.31	2.55	2.90	3.15	3.40	Earnings per sh A	4.40
.41	.45	.47	.50	.55	.60	.66	.73	.77	.87	.98	1.11	1.25	1.40	1.54	1.70	1.87	2.06	Div'd Decl'd per sh B ■ †	2.74
3.08	3.20	3.63	3.47	3.98	5.58	3.84	3.96	4.54	5.15	5.70	6.80	6.29	7.45	8.19	9.70	9.50	9.50	Cap'l Spending per sh	9.75
6.59	7.14	7.84	8.59	8.98	9.47	10.37	11.24	12.24	13.00	14.97	17.86	18.92	18.63	18.95	19.74	22.20	23.50	Book Value per sh C	30.00
1629.4	1635.7	1654.5	1683.4	1664.0	1696.0	1740.0	1772.0	1844.0	1872.0	1884.0	1912.0	1956.0	1960.0	1963.0	1987.0	2025.0	2025.0	Common Shs Outst'g D	2050.0
18.9	14.5	13.4	10.8	11.5	14.4	16.6	17.3	16.9	20.7	21.6	24.8	26.8	28.9	31.3	27.8	Bold figures are		Avg Ann'l P/E Ratio	24.0
1.00	.87	.89	.69	.72	.92	.93	.91	.85	1.09	1.09	1.34	1.43	1.48	1.69	1.62	Value Line		Relative P/E Ratio	1.35
2.7%	3.0%	3.5%	3.9%	4.0%	3.6%	3.3%	3.0%	3.0%	2.9%	2.8%	2.7%	2.4%	2.1%	1.9%	2.1%	estimates		Avg Ann'l Div'd Yield	2.6%

CAPITAL STRUCTURE as of 3/31/23
Total Debt $70641 mill. Due in 5 Yrs $29730 mill.
LT Debt $59007 mill. LT Interest $1568 mill.

(Total interest coverage: 4.4x)

Pension Assets-12/22 $4543 mill. Oblig $2711 mill.

Pfd Stock None

Common Stock 2,023,421,945 shs.

MARKET CAP: $155.4 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
15136	17021	17486	16155	17195	16727	19204	17997	17069	20956	27000	29500	Revenues ($mill)	37000
2062.0	2465.0	2752.0	2693.0	3074.0	3200.0	3769.0	4552.0	5021.0	5742.0	6380	6895	Net Profit ($mill)	9035
26.9%	32.3%	30.8%	29.3%	24.4%	28.6%	11.7%	13.0%	15.0%	18.2%	18.0%	18.0%	Income Tax Rate	18.0%
7.0%	6.7%	6.9%	8.2%	6.7%	6.6%	4.1%	4.6%	6.3%	4.3%	4.0%	4.0%	AFUDC % to Net Profit	4.0%
57.1%	55.0%	54.2%	53.3%	52.7%	44.0%	50.4%	53.5%	57.8%	58.5%	57.0%	59.0%	Long-Term Debt Ratio	60.0%
42.9%	45.0%	45.8%	46.7%	47.3%	56.0%	49.6%	46.5%	42.2%	41.5%	43.0%	41.0%	Common Equity Ratio	40.0%
42009	44283	49255	52159	59671	60926	74548	78457	88162	94485	104975	116675	Total Capital ($mill)	153100
52720	55705	61386	66912	72416	70334	82010	91803	99348	111059	125300	139350	Net Plant ($mill)	180100
6.2%	7.0%	6.8%	6.3%	6.3%	6.3%	6.0%	6.8%	6.6%	6.9%	7.0%	6.5%	Return on Total Cap'l	6.5%
11.4%	12.4%	12.2%	11.1%	10.9%	9.4%	10.2%	12.5%	13.5%	14.6%	14.0%	14.5%	Return on Shr. Equity	14.5%
11.4%	12.4%	12.2%	11.1%	10.9%	9.4%	10.2%	12.5%	13.5%	14.6%	14.0%	14.5%	Return on Com Equity E	14.5%
5.2%	6.0%	6.1%	4.4%	4.4%	3.2%	3.7%	5.0%	5.4%	6.1%	6.0%	5.5%	Retained to Com Eq	5.5%
54%	51%	50%	60%	60%	66%	64%	60%	60%	58%	59%	61%	All Div'ds to Net Prof	62%

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	NA	NA	+3.0
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 (yr-end)	+1.5	+1.5	+1.5
Fixed Charge Cov. (%)	301	284	370

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	0.5%	1.0%	11.5%
"Cash Flow"	7.5%	9.0%	7.0%
Earnings	8.0%	11.0%	9.5%
Dividends	11.0%	12.0%	10.0%
Book Value	8.0%	7.5%	8.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	4613	4204	4785	4395	17997
2021	3726	3927	4370	5046	17069
2022	2890	5183	6719	6164	20956
2023	6716	6550	7290	6444	27000
2024	6850	7400	7950	7300	29500

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.59	.65	.67	.40	2.31
2021	.67	.71	.75	.41	2.55
2022	.74	.81	.85	.51	2.90
2023	.84	.82	.95	.54	3.15
2024	.81	.91	1.05	.63	3.40

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.3125	.3125	.3125	.3125	1.25
2020	.35	.35	.35	.35	1.40
2021	.385	.385	.385	.385	1.54
2022	.425	.425	.425	.425	1.70
2023	.4675				

BUSINESS: NextEra Energy, Inc. is a holding company for Florida Power & Light Co. (FPL), which provides electricity to roughly 5.8 million customers in eastern, southern, & northwestern Florida. NextEra Energy Resources is a nonregulated power generator with nuclear, gas, & renewables. Has 55% stake in NextEra Energy Partners. Acquired Gulf Power 1/19; Florida City Gas 7/18. Revenue.: residential, about 55%; commercial/industrial/other, 45%. Generating sources: gas, 71%; nuclear, 21%; solar/other, 7%; purchased, 1%. Fuel costs: 30.5% of revenues. '22 depreciation rate: 3.4%. Employs 15,300. Chairman, President and CEO: John W. Ketchum. Inc.: Florida. Address: 700 Universe Blvd., Juno Beach, FL 33408. Tel.: 561-694-4000. Internet: www.nexteraenergy.com.

NextEra Energy is off to a solid start this year. The company reported March-period adjusted earnings of $0.84 per share, exceeding both our call and the analyst consensus by $0.04 and $0.08, respectively. Healthy bottom-line growth was driven by an 11.2% year-over-year increase in regulatory capital employed by the company's utility, Florida Power & Light. FP&L's allowable return on equity, achieved through electric rate pricing mechanisms as defined by the state regulatory process, is a healthy 10.8%. NextEra leadership is doing a good job of driving efficiencies and keeping costs under control. As such, we're comfortable with our full-year 2023 earnings-per-share estimate being just above management's targeted range of $2.98-$3.13.

Excellent utility fundamentals and the company's expertise in renewable energy should keep the growth engine revving. Florida is the fastest growing state in America, at triple the 0.5% national rate of population growth of the past five years. Unemployment is low and the labor participation rate is high. This results in transmission & distribution work, which along with reliability/hardiness projects in the storm-challenged state, help to keep regulatory capital (aka the rate base) rising. There is also a major opportunity over the next 10 years to expand solar capacity within the rate base from 5% of power generation to 35%. Meantime, the company's nonregulated subsidiary, NextEra Energy Resources, is a major nationwide player in the burgeoning renewable-energy arena.

There's been no recent news on the campaign finance controversy. As discussed in detail in our February report, the top executive at FP&L was accused of funneling $1.3 million into nonprofits, which used the funds to help defeat candidates who held positions contrary to the utility's best interests. He has since retired. A formal complaint was filed with the Federal Election Commision seven months ago, but thus far there is no indication that the matter will be pursued by state or federal prosecutors.

NextEra stock offers appealing appreciation potential to the midpoint of our 18-month Target Price Range.

Anthony J. Glennon *May 12, 2023*

(A) Diluted EPS. Excl. nonrecurring gains/(losses): '11, (6¢); '13, (20¢); '16, 12¢; '17, $1.22¢; '18, $1.80; '20, (83¢); '21, (74¢); '22, (80¢); 1Q '23, 20¢; disc. ops.: '13, 11¢. EPS may not sum to full yr. due to rounding. Next egs. report due late July. (B) Div'ds paid in mid-Mar., mid-June, mid-Sept., & mid-Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '22: $6.36/sh. (D) In mill., adj. for stock split. (E) Rate all'd on com. eq. in '22 (FPL): 9.8%-11.8%; Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	85
Price Growth Persistence	100
Earnings Predictability	95

NORTHWESTERN NDQ-NWE

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	
60.83	17.5 (Trailing: 18.5, Median: 17.0)	1.01	4.2%	VALUE LINE

TIMELINESS 3 Raised 4/14/23
SAFETY 2 Raised 7/27/18
TECHNICAL 4 Raised 4/7/23
BETA .90 (1.00 = Market)

High:	38.0	47.2	58.7	59.7	63.8	64.5	65.7	76.7	80.5	70.8	63.1	61.2
Low:	33.0	35.1	42.6	48.4	52.2	55.7	50.0	57.3	45.1	53.2	48.7	53.4

Target Price Range 2026 | 2027 | 2028

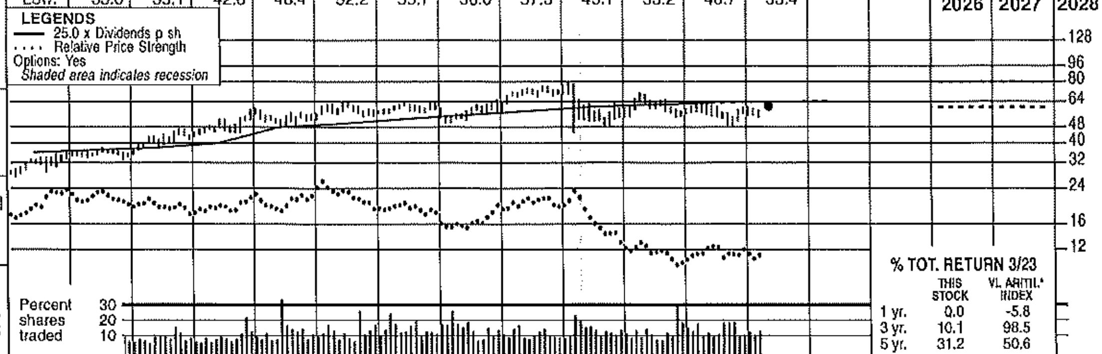
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$48-$73 $61 (0%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+30%)	10%
Low	60	(Nil)	4%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	140	176	169
to Sell	121	97	115
Hld's(000)	56756	56117	57154



% TOT. RETURN 3/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	0.0	-5.8
3 yr.	10.1	98.5
5 yr.	31.2	50.6

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
30.79	35.09	31.72	30.66	30.80	28.76	29.80	25.68	25.21	26.01	26.45	23.81	24.93	23.70	25.38	24.74	*24.60*	*25.80*	Revenues per sh	*28.25*
3.70	4.40	4.62	4.76	5.42	5.18	5.45	5.39	5.92	6.74	6.76	6.96	7.07	6.86	6.92	6.46	*6.80*	*7.20*	"Cash Flow" per sh	*8.35*
1.44	1.77	2.02	2.14	2.53	2.26	2.46	2.99	2.90	3.39	3.34	3.40	3.53	3.21	3.50	3.29	*3.45*	*3.60*	Earnings per sh A	*4.15*
1.28	1.32	1.34	1.36	1.44	1.48	1.52	1.60	1.92	2.00	2.10	2.20	2.30	2.40	2.48	2.52	*2.56*	*2.60*	Div'd Decl'd per sh B ■ †	*2.76*
3.00	3.47	5.26	6.30	5.20	5.89	5.95	5.76	5.89	5.96	5.60	5.64	6.26	8.02	8.03	8.62	*9.10*	*7.50*	Cap'l Spending per sh	*6.50*
21.12	21.25	21.86	22.64	23.68	25.09	26.60	31.50	33.22	34.68	36.44	38.60	40.42	41.10	43.28	44.61	*47.50*	*48.50*	Book Value per sh C	*52.30*
38.97	35.93	36.00	36.23	36.28	37.22	38.75	46.91	48.17	48.33	49.37	50.32	50.45	50.59	54.06	59.74	*62.00*	*62.00*	Common Shs Outst'g D	*62.00*
21.7	13.9	11.5	12.9	12.6	15.7	16.9	16.2	18.4	17.2	17.8	16.8	19.9	18.6	17.4	17.3	*Bold figures are*		Avg Ann'l P/E Ratio	*16.5*
1.15	.84	.77	.82	.79	1.00	.95	.85	.93	.90	.90	.91	1.06	.96	.94	1.01	*Value Line*		Relative P/E Ratio	*.90*
4.1%	5.4%	5.7%	4.9%	4.5%	4.2%	3.7%	3.3%	3.6%	3.4%	3.5%	3.9%	3.3%	4.0%	4.1%	4.4%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 12/31/22
Total Debt $2630.8 mill. Due in 5 Yrs $1111.4 mill.
LT Debt $2483.2 mill. LT Interest $95.0 mill.
Incl. $8.8 mill. finance leases.
(Total Interest Coverage: 2.5x)

Pension Assets-12/22 $441.5 mill. Oblig $521.8 mill.

Pfd Stock None

Common Stock 59,768,222 shs. as of 2/10/23

MARKET CAP: $3.6 billion (Mid Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
1154.5	1204.9	1214.3	1257.2	1305.7	1198.1	1257.9	1198.7	1372.3	1477.8	*1525*	*1600*	Revenues ($mill)	*1750*
94.0	120.7	138.4	164.2	162.7	171.1	179.3	162.6	181.6	185.5	*210*	*225*	Net Profit ($mill)	*255*
13.2%	--	13.7%	--	7.6%	--	1.6%	--	.9%	--	*3.0%*	*6.0%*	Income Tax Rate	*12.0%*
8.7%	8.9%	9.8%	4.3%	5.2%	3.4%	4.6%	6.0%	14.9%	18.5%	*14.0%*	*13.0%*	AFUDC % to Net Profit	*12.0%*
53.5%	53.4%	53.1%	52.0%	50.2%	52.2%	52.5%	52.8%	52.2%	48.2%	*47.5%*	*46.5%*	Long-Term Debt Ratio	*48.0%*
46.5%	46.6%	46.9%	48.0%	49.8%	47.8%	47.5%	47.2%	47.8%	51.8%	*52.5%*	*53.5%*	Common Equity Ratio	*52.0%*
2215.7	3168.0	3408.6	3493.9	3614.5	4064.6	4289.8	4409.1	4693.1	5148.3	*5625*	*5625*	Total Capital ($mill)	*6200*
2690.1	3758.0	4059.5	4214.9	4358.3	4521.3	4700.9	4952.9	5247.2	5657.5	*6000*	*6250*	Net Plant ($mill)	*6725*
5.5%	4.8%	5.2%	5.9%	5.6%	5.2%	5.2%	4.6%	4.6%	4.5%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.0%*
9.1%	8.2%	8.6%	9.8%	9.0%	8.8%	8.8%	7.8%	7.8%	7.0%	*7.0%*	*7.5%*	Return on Shr. Equity	*8.0%*
9.1%	8.2%	8.6%	9.8%	9.0%	8.8%	8.8%	7.8%	7.8%	7.0%	*7.0%*	*7.5%*	Return on Com Equity E	*8.0%*
3.5%	3.8%	3.0%	4.1%	3.4%	3.2%	3.1%	2.0%	2.3%	1.7%	*2.0%*	*2.0%*	Retained to Com Eq	*2.5%*
61%	54%	65%	58%	62%	64%	64%	74%	71%	76%	*74%*	*72%*	All Div'ds to Net Prof	*67%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-4.4	+.7	+3.7
Avg. Indust. Use (MWH)	33526	31792	34079
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	2073
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+1.6	+1.5
Fixed Charge Cov. (%)	247	245	219

BUSINESS: NorthWestern Corporation (doing business as NorthWestern Energy) supplies electricity & gas in the Upper Midwest and Northwest, serving 463,000 electric customers in Montana and South Dakota and 301,000 gas customers in Montana, South Dakota, and Nebraska. Electric revenue breakdown: residential, 45%; commercial, 46%; industrial, 5%; other, 4%. Generating sources: coal, 28%; hydro, 26%; wind, 6%; natural gas, 6%; purchased power, 34%. Fuel costs: 33% of revenues. 2022 reported depreciation rate: 2.8%. Has approximately 1,500 employees. Board Chair: Dana J. Dykhouse. President and CEO: Brian B. Bird. Incorporated: DE. Address: 3010 West 69th Street, Sioux Falls, SD 57108. Telephone: 605-978-2900. Internet: www.northwesternenergy.com.

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-2.0%	-1.0%	2.5%
"Cash Flow"	3.0%	1.0%	3.5%
Earnings	3.5%	1.0%	3.5%
Dividends	5.5%	4.0%	2.0%
Book Value	6.0%	4.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	335.3	269.4	280.6	313.4	1198.7
2021	400.8	298.2	326.0	347.3	1372.3
2022	394.5	323.0	335.1	425.2	1477.8
2023	*415*	*345*	*340*	*425*	*1525*
2024	*435*	*360*	*355*	*450*	*1600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	1.00	.43	.58	1.21	3.21
2021	1.24	.59	.70	.97	3.50
2022	1.08	.58	.47	1.16	3.29
2023	*1.14*	*.60*	*.57*	*1.14*	*3.45*
2024	*1.19*	*.62*	*.60*	*1.19*	*3.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.575	.575	.575	.575	2.30
2020	.60	.60	.60	.60	2.40
2021	.62	.62	.62	.62	2.48
2022	.63	.63	.63	.63	2.52
2023	.64				

NorthWestern has reached a settlement agreement in its Montana electric and natural gas rate review. In early April, the utility hammered out an acceptable consensus with the Montana Consumer Counsel, the Montana Large Customer Group, and Walmart Inc. The agreement has been submitted to the Montana Public Service Commission (MPSC) for the regulatory body's consideration. The MPSC had already granted an interim rate hike, starting from late September, so that NorthWestern could begin to recoup high purchased power and natural gas costs. The recently settled base rates would increase annual electric and natural gas revenues by $67.4 million and $14.1 million, respectively. Those levels are predicated on the same authorized ROEs (return on equity), 9.65% for electric and 9.55% for gas, that were last agreed upon in 2015 and 2017, respectively. Assuming the MPSC signs off on the agreement, the utility will have gotten about two-thirds of what it was asking for in rate hikes. Importantly, NorthWestern would also receive pricing mechanisms geared towards reducing regulatory lag.

Boosting the rate base should help reignite growth, too. (The rate base is the dollar value of assets for which a utility is allowed to earn an economic return.) In June, NorthWestern completed an $83 million, 58-megawatt plant in South Dakota, with the potential for added capacity in the state down the road. A $275 million, 175-mw facility in Montana was due to be operational later this year before a state judge recently stepped in and revoked the company's air quality permit as part of a lawsuit filed by an environmental group. The bench ruled that Montana environmental regulators had not adequately considered the impact of greenhouse gas emissions over the life of the project. This is unprecedented under state law, thus we doubt it will hold up in an appeal.

Neutrally ranked NorthWestern stock has outperformed the *Value Line Utility Index* by 15 percentage points over the past six months. We think most of the good news regarding the high probability of a constructive conclusion to the company's general rate case is already reflected in the recent share price.

Anthony J. Glennon *April 21, 2023*

(A) Diluted egs. Excl. nonrec. gains/(losses): '12, 40¢; '15, 27¢; '10, 52¢; '19, 45¢; '20, (15¢); '21, 10¢; '22, (4¢). '20 EPS don't sum due to rounding. Next egs. report due April 27th. (B) Div'ds paid in late Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. def'd charges. In '22: $17.98/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in MT in '19 (elec.): 9.65%; in '17 (gas): 9.55%; in SD in '15: none specified; in NE in '07: 10.4%. Regulatory Climate: Below Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	35
Earnings Predictability	90

OGE ENERGY CORP. NYSE-OGE

RECENT PRICE 34.96 | P/E RATIO 17.5 (Trailing: 16.6 Median: 18.0) | RELATIVE P/E RATIO 1.07 | DIV'D YLD 4.7% | VALUE LINE

TIMELINESS 4 Lowered 5/12/23
SAFETY 2 Lowered 12/18/15
TECHNICAL 3 Raised 5/19/23
BETA 1.00 (1.00 = Market)

High: 30.1 40.0 39.3 36.5 34.2 37.4 41.8 45.8 46.4 38.6 42.9 40.4
Low: 25.1 27.7 32.8 24.2 23.4 32.6 29.6 38.0 23.0 29.2 33.3 34.2

Target Price Range 2026 | 2027 | 2028

LEGENDS
— 25.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/13
Options: Yes
Shaded area indicates recession

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$30-$50	$40 (15%)

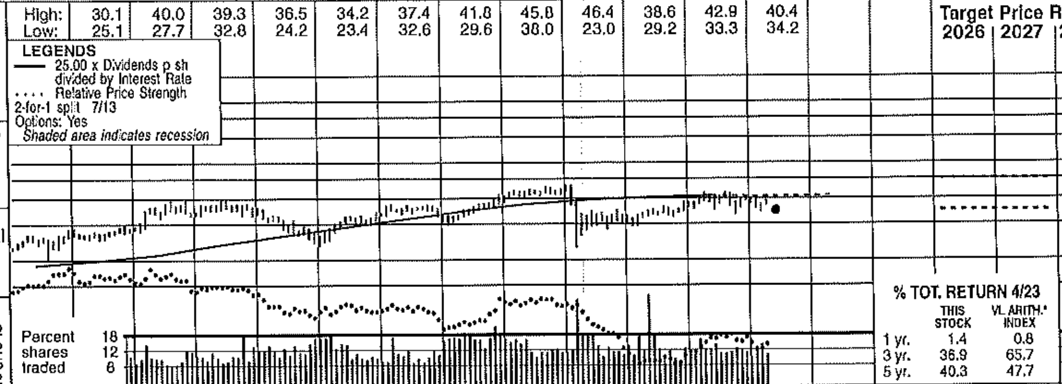
2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+45%)	13%
Low	35	(Nil)	5%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	218	185	262
to Sell	182	192	155
Hld's(000)	136256	136256	139192

Percent shares traded 18 12 6



% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.4	0.8
3 yr.	36.9	65.7
5 yr.	40.3	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
20.68	21.77	14.79	19.04	19.96	16.58	14.45	12.30	11.00	11.31	11.32	11.37	11.15	10.61	18.26	16.86	17.25	18.00	Revenues per sh	19.00
2.39	2.40	2.69	3.01	3.31	3.69	3.46	3.40	3.23	3.31	3.34	3.74	4.02	4.03	4.44	4.56	4.60	4.65	"Cash Flow" per sh	6.25
1.32	1.25	1.33	1.50	1.73	1.79	1.94	1.98	1.69	1.69	1.92	2.12	2.24	2.08	2.36	2.25	2.00	2.15	Earnings per sh A	3.15
.68	.70	.71	.73	.76	.80	.85	.95	1.05	1.16	1.27	1.40	1.51	1.58	1.63	1.64	1.66	1.78	Div'd Decl'd per sh B ■	1.85
3.04	4.01	4.37	4.36	6.48	5.85	4.99	2.86	2.74	3.31	4.13	2.87	3.18	3.25	3.89	5.25	4.75	4.75	Cap'l Spending per sh	4.75
9.16	10.14	10.52	11.73	13.06	14.00	15.30	16.27	16.66	17.24	19.28	20.06	20.69	18.15	20.27	21.95	22.25	23.10	Book Value per sh C	26.00
183.60	187.00	194.00	195.20	196.20	197.60	198.50	199.40	199.70	199.70	199.70	199.70	200.10	200.10	200.10	200.20	200.20	200.20	Common Shs Outst'g D	200.20
13.8	12.4	10.8	13.3	14.4	15.2	17.7	18.3	17.7	17.7	18.3	16.5	19.0	16.2	14.3	17.2	Bold figures are		Avg Ann'l P/E Ratio	14.0
.73	.75	.72	.85	.90	.97	.99	.96	.89	.93	.92	.89	1.01	.83	.77	1.00	Value Line		Relative P/E Ratio	.80
3.8%	4.5%	5.0%	3.7%	3.1%	2.9%	2.5%	2.6%	3.5%	3.9%	3.6%	4.0%	3.5%	4.7%	4.8%	4.5%	estimates		Avg Ann'l Div'd Yield	4.4%

CAPITAL STRUCTURE as of 3/31/23
Total Debt $4994.1 mill. Due in 5 Yrs $1731.5 mill.
LT Debt $3994.1 mill. LT Interest $158.7 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $5.7 mill.

Pension Assets-12/22 $486.0 mill.
Oblig $502.9 mill.

Pfd Stock None

Common Stock 200,287,364 shs.

MARKET CAP: $7.0 billion (Mid Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
2867.7	2453.1	2196.9	2259.2	2261.1	2270.3	2231.6	2122.3	3653.7	3375.7	3450	3600	Revenues ($mill)	3800
387.6	395.8	337.6	338.2	384.3	425.5	449.6	415.9	472.5	452.5	410	430	Net Profit ($mill)	630
24.9%	30.4%	29.2%	30.5%	32.5%	14.5%	7.4%	13.2%	11.5%	12.0%	12.0%	12.0%	Income Tax Rate	12.0%
2.6%	1.7%	3.7%	6.4%	15.0%	8.3%	1.6%	1.6%	2.2%	2.0%	2.0%	2.0%	AFUDC % to Net Profit	2.0%
43.1%	45.9%	44.3%	41.1%	41.7%	42.0%	43.6%	49.0%	52.6%	49.8%	52.0%	52.0%	Long-Term Debt Ratio	50.0%
56.9%	54.1%	55.7%	58.9%	58.3%	58.0%	56.4%	51.0%	47.4%	52.4%	48.0%	48.0%	Common Equity Ratio	50.0%
5337.2	5999.7	5971.6	5849.6	6600.7	6902.0	7334.7	7126.2	8552.7	8962.0	9400	9750	Total Capital ($mill)	10400
6672.8	6979.9	7322.4	7696.2	8339.9	8643.8	9044.6	9374.6	9832.9	10546.8	10830	11000	Net Plant ($mill)	12075
8.6%	7.8%	6.9%	7.0%	7.0%	7.3%	7.1%	6.9%	6.4%	5.9%	6.5%	6.5%	Return on Total Cap'l	7.5%
12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	11.6%	11.0%	12.0%	12.0%	Return on Shr. Equity	13.0%
12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	11.6%	11.0%	12.0%	12.0%	Return on Com Equity E	13.0%
7.3%	6.5%	4.0%	3.3%	3.5%	3.8%	3.6%	2.8%	3.6%	3.0%	4.5%	4.5%	Retained to Com Eq	5.5%
43%	47%	61%	67%	64%	64%	67%	76%	69%	73%	81%	81%	All Div'ds to Net Prof	57%

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-4.9	+2.6	+8.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.40	7.68	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6437	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+1.4	NA
Fixed Charge Cov. (%)	326	336	335

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-3.0%	5.0%	5.5%
"Cash Flow"	2.5%	5.0%	7.0%
Earnings	3.0%	4.5%	6.5%
Dividends	7.5%	6.5%	3.0%
Book Value	4.0%	1.5%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	431.3	503.5	702.1	485.4	2122.3
2021	1630	577.4	864.4	581.3	3653.7
2022	589.3	803.7	1270	711.9	3375.7
2023	557.2	785	1280	827.8	3450
2024	650	850	1300	800	3600

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.23	.51	1.04	.30	2.08
2021	.26	.56	1.26	.28	2.36
2022	.33	.36	1.31	.25	2.25
2023	.19	.44	1.16	.21	2.00
2024	.35	.30	1.25	.25	2.15

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.365	.365	.365	.388	1.48
2020	.3875	.3875	.3875	.4025	1.57
2021	.4025	.4025	.4025	.41	1.62
2022	.41	.41	.41	.4141	1.64
2023	.41	.41			

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 879,000 customers in Oklahoma (84% of electric revenues) and western Arkansas (8%); wholesale is (8%). Owns 3% of Energy Transfer's limited partnership units. Electric revenue breakdown: residential, 44%; commercial, 25%; industrial, 11%; oilfield, 10%; other, 10%. Generating sources: gas, 25%; coal, 21%; wind, 6%; purchased, 48%. Fuel costs: 58% of revenues. '22 reported depreciation rate (utility): 2.6%. Has 2,200 employees. Chairman, President and Chief Executive Officer: Sean Trauschke. Incorporated: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, OK 73101-0321. Tel.: 405-553-3000. Internet: www.oge.com.

OGE Energy's utility subsidiary in Arkansas had its rate settlement approved by the Arkansas Public Service Commission. The utility implemented new fuel rates which went into effect on April 1st. In Oklahoma, the company is likely to file a general rate case in the second half of this year. Too, in April, the Oklahoma Corporation Commission approved the utility's 2021 fuel prudency audit.

We think the challenging operating environment will continue to pressure margins in 2023. Accordingly, we have lowered our full-year 2023 EPS guidance due to the rising interest rate environment and inflationary stress, which is significantly increasing borrowing costs. Our 2023 EPS estimate of $2.00 is at the midpoint of OGE Energy's targeted range of $1.93-$2.07, and in line with the company's long-term earnings per share growth forecast of 5%-7% annually, based off original 2021 guidance on a consolidated basis.

Rate relief and the company's transformation to a fully focused electric utility should be a main driver to results in the near-intermediate and long-term. OGE is now a pure-play electric utility after completing its exit from the natural gas midstream arena, which should reduce business risk and attract investors. The Inflation Reduction Act will also help improve the challenging macroeconomic environment and provide assistance in the transition to providing affordable, clean energy. Our 2024 bottom-line projection is staying put, as we think profits will recover to $2.15 a share.

OGE shares have continued to struggle of late. Indeed, the stock has dropped more than 6% in value since our early March report, and is now down nearly 15% over the past six months. Too, this issue was recently downgraded one notch in our Timeliness Ranking System to 4 (Below Average). On a positive note, the dividend continues to be this issue's most notable feature. These shares boast a attractive quarterly dividend yield of 4.7%, which sits well above the industry average and the *Value Line* median. The utility also holds a solid dividend growth potential rate of 3.0%, which would maintain a generous payout ratio.

Zachary J. Hodgkinson *June 9, 2023*

(A) Diluted EPS. Excl. nonrecurring gains (losses): '15, (33¢); '17, $1.18; '19, (8¢); '20, ($2.95); '21, $1.32; '22, $1.06; gain on discont. ops.: '19 & '21 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '22: $6.15/sh. (D) In mill., adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in OK in '19: 9.5%; in AR in '18: 9.5%; earned on avg. com. eq., '21: 12.7%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	30
Earnings Predictability	95

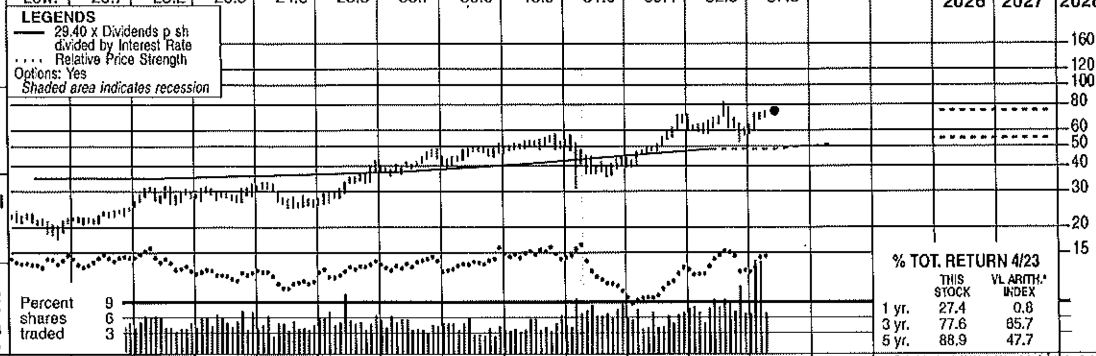
OTTER TAIL CORP. NDQ-OTTR

RECENT PRICE 74.79 | P/E RATIO 15.7 (Trailing: 11.4; Median: 20.0) | RELATIVE P/E RATIO 0.96 | DIV'D YLD 2.3% | VALUE LINE

TIMELINESS 2 Raised 5/12/23
SAFETY 2 Raised 6/17/16
TECHNICAL 2 Raised 4/14/23
BETA .85 (1.00 = Market)

High:	25.3	31.9	32.7	33.4	42.6	48.7	51.9	57.7	56.9	71.7	82.5	79.1
Low:	20.7	25.2	26.5	24.8	25.8	35.7	39.0	45.9	31.0	39.4	52.6	57.3

Target Price Range 2026 | 2027 | 2028



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$37-$86	$62 (-20%)

2026-28 PROJECTIONS

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

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	121	140	117
to Sell	103	95	133
Hld's(000)	20044	20598	20465

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.4	0.8
3 yr.	77.6	65.7
5 yr.	88.9	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
41.50	37.06	29.03	31.08	29.86	23.76	24.63	21.48	20.60	20.42	21.47	23.10	22.90	21.46	28.80	35.08	30.05	29.75	Revenues per sh	31.20
3.55	2.81	2.76	2.60	2.36	2.71	3.02	3.09	3.14	3.44	3.70	3.96	4.11	4.29	6.45	8.77	6.40	5.95	"Cash Flow" per sh	6.00
1.78	1.09	.71	.38	.45	1.05	1.37	1.55	1.56	1.60	1.86	2.06	2.17	2.34	4.23	6.78	4.75	3.50	Earnings per sh A	3.65
1.17	1.19	1.19	1.19	1.19	1.19	1.19	1.21	1.23	1.25	1.28	1.34	1.40	1.48	1.56	1.65	1.75	1.81	Div'd Decl'd per sh B ■	2.20
5.43	7.51	4.95	2.38	2.04	3.20	4.53	4.40	4.23	4.10	3.36	2.66	5.16	8.96	4.14	4.11	5.90	6.00	Cap'l Spending per sh	6.25
17.55	19.14	18.78	17.57	15.83	14.43	14.75	15.39	15.98	17.03	17.62	18.38	19.46	21.00	23.84	29.24	29.80	31.15	Book Value per sh C	34.25
29.85	35.38	35.81	36.00	36.10	36.17	36.27	37.22	37.86	39.35	39.56	39.66	40.16	41.47	41.55	41.63	41.90	42.00	Common Shs Outst'g D	42.50
19.0	30.1	31.2	NMF	47.5	21.7	21.1	18.8	18.2	20.2	22.1	22.2	23.5	18.3	12.3	9.5	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	17.5
1.01	1.81	2.08	NMF	2.98	1.38	1.19	.99	.92	1.06	1.11	1.20	1.25	.94	.66	.55			Relative P/E Ratio	.95
3.5%	3.6%	5.4%	5.7%	5.6%	5.2%	4.1%	4.1%	4.3%	3.9%	3.1%	2.9%	2.7%	3.5%	3.0%	2.5%			Avg Ann'l Div'd Yield	3.4%
						893.3	799.3	779.8	803.5	849.4	916.4	919.5	890.1	1196.8	1460.2	1260	1250	Revenues ($mill)	1325
						50.2	56.9	58.6	62.0	73.9	82.3	86.8	95.9	176.8	282.3	200	150	Net Profit ($mill)	155
						21.3%	22.5%	27.0%	24.5%	25.5%	15.0%	16.7%	17.4%	16.9%	20.5%	20.0%	20.0%	Income Tax Rate	20.0%
						5.6%	3.9%	3.5%	2.2%	2.3%	4.1%	4.9%	6.4%	.8%	.9%	3.0%	3.5%	AFUDC % to Net Profit	4.0%
						42.1%	46.5%	42.4%	43.0%	41.3%	44.7%	46.9%	41.8%	42.6%	40.0%	41.5%	41.5%	Long-Term Debt Ratio	42.5%
						57.9%	53.5%	57.6%	57.0%	58.7%	55.3%	53.1%	58.2%	57.4%	58.5%	58.5%	58.5%	Common Equity Ratio	57.5%
						924.4	1071.3	1051.0	1175.4	1187.3	1318.9	1471.1	1495.4	1724.8	2041.1	2140	2250	Total Capital ($mill)	2525
						1167.0	1268.5	1387.8	1477.2	1539.6	1581.1	1753.8	2049.3	2124.6	2212.7	2355	2475	Net Plant ($mill)	2700
						6.8%	6.7%	6.8%	6.5%	7.3%	7.3%	7.0%	7.4%	11.1%	12.0%	9.0%	8.5%	Return on Total Cap'l	7.5%
						9.4%	9.9%	9.7%	9.3%	10.6%	11.3%	11.1%	11.0%	17.8%	18.0%	13.5%	13.0%	Return on Shr. Equity E	11.5%
						9.3%	9.9%	9.7%	9.3%	10.6%	11.3%	11.1%	11.0%	17.8%	18.0%	13.5%	13.0%	Return on Com Equity	11.5%
						1.2%	2.2%	2.0%	2.1%	3.3%	4.0%	4.0%	4.1%	11.3%	12.4%	7.5%	7%	Retained to Com Eq	5.0%
						87%	78%	79%	78%	69%	65%	64%	63%	37%	24%	44%	52%	All Div'ds to Net Prof	60%

CAPITAL STRUCTURE as of 3/31/23
Total Debt $823.9 mill. Due in 5 Yrs $207.8 mill.
LT Debt $823.9 mill. LT Interest $31.6 mill.
(LT interest earned: 9.7x)

Leases, Uncapitalized Annual rentals $5.0 mill.
Pension Assets-12/22 $387.2 mill. Oblig $416.7 mill.

Pfd Stock None

Common Stock 41,710,621 shs. as of 4/28/23

MARKET CAP: $3.1 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-3.9	+.3	+16.8
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. (%)	405	651	653

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '26-'28
Revenues	-1.0%	4.0%	5.0%
"Cash Flow"	7.5%	9.5%	5.5%
Earnings	18.0%	14.5%	4.5%
Dividends	2.5%	4.0%	7.0%
Book Value	3.5%	6.0%	8.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	234.7	192.8	235.8	226.8	890.1
2021	261.7	285.6	316.3	333.2	1196.8
2022	374.9	400.0	383.9	301.4	1460.2
2023	339.1	330.9	305	285	1260
2024	320	330	310	290	1250

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.60	.42	.87	.45	2.34
2021	.73	1.01	1.26	1.23	4.23
2022	1.72	2.05	2.01	1.00	6.78
2023	1.49	1.50	1.01	.75	4.75
2024	.80	1.00	1.00	.70	3.50

Cal-endar	QUARTERLY DIVIDENDS PAID D ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.35	.35	.35	.35	1.40
2020	.37	.37	.37	.37	1.48
2021	.39	.39	.39	.39	1.56
2022	.4125	.4125	.4125	.4125	1.65
2023	.4375				

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to 133,000 customers in Minnesota (52% of retail electric revenues), North Dakota (38%), and South Dakota (10%). Electric rev. breakdown: residential, 32%; commercial & farms, 36%; industrial, 30%; other, 2%. Generating sources: coal, 38%; wind & other, 18%; purchased, 44%. Fuel costs: 10% of revenues. Also has operations in manufacturing and plastics (72% of '22 operating income). '22 deprec. rate: 3.0%. Has 2,500 employees. Chairman: Nathan I. Partain. President & CEO: Charles S. MacFarlane. Inc.: Minnesota. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, Minnesota 56538-0496. Tel.: 866-410-8780. Internet: www.ottertail.com.

The price of Otter Tail stock has continued to surge. The quotation has risen more than 5% since our March report and is up 15% over the past 12 months due to a string of better-than-expected performances of late. Indeed, the company has raised its earnings guidance for 2023 on the heels of its strong first quarter results. Management now expects the bottom-line to wind up in a range of $4.55-$4.85 a share, from the initial guidance range of $3.70-$4.06 per share. While the bottom-line will likely decline over the next few years as conditions normalize within the utility's plastics division, the electric and manufacturing segments remain a main driver to earnings, and both grew by double digits in the first quarter of 2023. Too, Otter Tail continues to benefit from elevated PVC pipe pricing, as PVC pipe remains higher-than-anticipated, near historic highs. All told, we look for 2023 earnings of $4.75 per share.

We expect the company's bottom line to decline in 2024 and beyond as demand for PVC pipe is dropping noticeably. The Plastics segment earnings decreased 34%, while sales volumes declined 46% versus 2022 levels. Margins should begin to compress in the second half of this year, causing sales prices of PVC pipe to recede. Otter Tail expects the new normal level of plastics segment earnings to be around $36-$41 million. As a result, our 2024 earnings per share estimate is staying put at $3.50.

Otter Tail is making progress in a number of capital projects. In May, the Federal Energy Regulatory commission approved incentive rate treatment for its investments in the Jamestown project and the Big Stone South Project. Too, Hoot Lake Solar, a 49 megawatt solar project is approximately 85% complete and is expected to be in service by the end of the year.

This stock is trading near the high end of our 3-to 5-year Target Price Range. Near-term potential is more appealing. Otter Tail has outperformed nearly all of its peers of late, and these shares are ranked Above Average (2) for Timeliness. Meanwhile, this issue offers a dividend yield of 2.3%, which is just below-average for a utility.

Zachary J. Hodgkinson *June 9, 2023*

(A) Dil. EPS. Excl. nonrec. gains (loss): '10, (44¢); '11, 26¢; '13, 2¢; gains (losses) from disc. ops.: '11, ($1.11); '12, ($1.22); '13, 2¢; '14, 2¢; '15, 2¢; '16, 1¢; '17, 1¢. '19 EPS may not sum due to rounding. Next earnings report due early Aug. (B) Div'ds histor. pd. in early Mar., Jun., Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '22: $4.10/sh. (D) In mill. (E) Rate all'd on com. eq. in MN in '22: 9.48%; in ND in '18: 9.77%; in SD in '19: 8.75%; earned on avg. com. eq., '21: 19.2%.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	70
Earnings Predictability	65

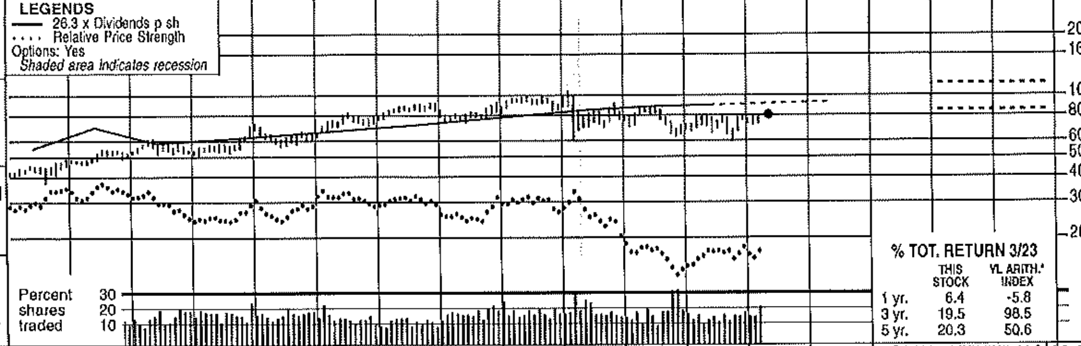
PINNACLE WEST NYSE-PNW

RECENT PRICE 80.42 | P/E RATIO 19.9 (Trailing: 18.8; Median: 17.0) | RELATIVE P/E RATIO 1.15 | DIV'D YLD 4.3% | VALUE LINE

TIMELINESS 4 Lowered 3/17/23
SAFETY 2 Lowered 10/22/21
TECHNICAL 3 Lowered 3/17/23
BETA .90 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	54.7	61.9	71.1	73.3	82.8	92.5	92.6	99.8	105.5	88.5	80.6	81.6
Low:	45.9	51.5	51.2	56.0	62.5	75.8	73.4	81.6	60.1	62.8	59.0	71.7

LEGENDS
— 26.3 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2026 | 2027 | 2028

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$50-$89	$70 (-15%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	115	(+45%)	13%
Low	85	(+5%)	6%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	249	227	299
to Sell	192	208	175
Hld's(000)	97870	97447	97877

Percent shares traded 30 20 10

% TOT. RETURN 3/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.4	-5.8
3 yr.	19.5	98.5
5 yr.	20.3	50.6

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
35.07	33.37	32.50	30.01	29.67	30.09	31.35	31.58	31.50	31.42	31.90	32.93	30.87	31.81	33.66	38.21	*38.35*	*39.00*	Revenues per sh	*41.65*
9.29	8.13	8.08	6.85	7.52	7.92	8.15	8.09	9.09	9.39	9.79	11.41	11.13	10.86	12.23	13.44	*13.25*	*13.30*	"Cash Flow" per sh	*15.00*
2.96	2.12	2.26	3.08	2.99	3.50	3.66	3.58	3.92	3.95	4.43	4.54	4.77	4.87	5.47	4.26	*4.15*	*4.50*	Earnings per sh A	*5.70*
2.10	2.10	2.10	2.10	2.10	2.67	2.23	2.33	2.44	2.56	2.70	2.87	3.04	3.23	3.36	3.42	*3.48*	*3.54*	Div'd Decl'd per sh B ■	*3.75*
9.37	9.46	7.64	7.03	8.26	8.24	9.36	8.38	9.84	11.64	12.80	10.73	10.76	11.93	13.04	15.09	*14.00*	*14.50*	Cap'l Spending per sh	*14.50*
35.15	34.16	32.69	33.86	34.98	36.20	38.07	39.50	41.30	43.15	44.80	46.59	48.30	49.96	52.26	53.45	*54.00*	*56.50*	Book Value per sh C	*61.75*
100.49	100.89	101.43	108.77	109.25	109.74	110.18	110.57	110.98	111.34	111.75	112.10	112.44	112.76	113.01	113.17	*113.50*	*118.00*	Common Shs Outst'g D	*120.00*
14.9	16.1	13.7	12.6	14.6	14.3	15.3	15.9	16.0	18.7	19.3	17.8	19.4	16.7	14.1	17.1	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
.79	.97	.91	.80	.92	.91	.86	.84	.81	.96	.97	.96	1.03	.86	.76	.99	*Value Line*		Relative P/E Ratio	*.95*
4.8%	6.2%	6.8%	5.4%	4.8%	5.3%	4.0%	4.1%	3.9%	3.5%	3.2%	3.5%	3.3%	4.0%	4.3%	4.7%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*
						3454.6	3491.6	3495.4	3498.7	3565.3	3691.2	3471.2	3587.0	3803.8	4324.4	*4350*	*4600*	Revenues ($mill)	*5000*
						406.1	397.6	437.3	442.0	497.8	511.0	538.3	550.6	618.7	483.6	*470*	*525*	Net Profit ($mill)	*685*
						34.4%	34.2%	34.3%	33.9%	32.5%	20.2%	- -	12.1%	14.8%	13.0%	*13.5%*	*13.5%*	Income Tax Rate	*13.5%*
						10.0%	11.6%	11.8%	14.1%	13.9%	15.2%	9.3%	9.5%	10.1%	15.2%	*14.0%*	*13.0%*	AFUDC % to Net Profit	*12.0%*
						40.0%	41.0%	43.0%	45.6%	48.9%	47.0%	47.1%	52.8%	53.9%	56.1%	*56.0%*	*52.5%*	Long-Term Debt Ratio	*56.0%*
						60.0%	59.0%	57.0%	54.4%	51.1%	53.0%	52.9%	47.2%	46.1%	43.9%	*44.0%*	*47.5%*	Common Equity Ratio	*44.0%*
						6990.9	7398.7	8046.3	8825.4	9796.4	9861.1	10263	11948	12820	13790	*13900*	*14025*	Total Capital ($mill)	*16800*
						10889	11194	11809	12714	13445	14030	14523	15159	15987	16854	*17425*	*18100*	Net Plant ($mill)	*20000*
						7.1%	6.4%	6.4%	6.0%	6.1%	6.2%	6.3%	5.5%	5.8%	4.5%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.0%*
						9.7%	9.1%	9.5%	9.2%	9.9%	9.8%	9.9%	9.8%	10.5%	8.0%	*7.5%*	*8.0%*	Return on Shr. Equity	*9.5%*
						9.7%	9.1%	9.5%	9.2%	9.9%	9.8%	9.9%	9.8%	10.5%	8.0%	*7.5%*	*8.0%*	Return on Com Equity E	*9.5%*
						4.1%	3.5%	3.9%	3.5%	4.2%	3.9%	3.8%	3.5%	4.2%	1.7%	*1.5%*	*1.5%*	Retained to Com Eq	*3.0%*
						58%	62%	59%	62%	58%	60%	61%	64%	60%	76%	*84%*	*78%*	All Div'ds to Net Prof	*66%*

CAPITAL STRUCTURE as of 12/31/22
Total Debt $8132.7 mill. Due In 5 Yrs $2100.7 mill.
LT Debt $7741.3 mill. LT Interest $265.5 mill.
(Total Interest Coverage: 3.0x)

Leases, Uncapitalized Annual rentals $18.1 mill.

Pension Assets-12/21 $2829.5 mill. Oblig $2809.5 mill.

Pfd Stock None

Common Stock 113,175,507 shs. as of 2/21/23
MARKET CAP: $9.1 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	+5.0	-.1	+4.4
Avg. Indust. Use (MWH)	766	808	849
Avg. Indust. Revs. per KWH (¢)	7.62	8.11	9.20
Capacity at Peak (Mw)	9094	8726	8612
Peak Load, Summer (Mw)	7660	7580	7587
Annual Load Factor (%)	45.5	45.9	48.1
% Change Customers (yr-end)	+2.3	+2.2	+2.1
Fixed Charge Cov. (%)	318	317	226

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	1.5%	2.0%	*3.0%*
"Cash Flow"	5.0%	5.5%	*3.5%*
Earnings	4.5%	3.5%	*2.5%*
Dividends	4.0%	5.5%	*2.0%*
Book Value	4.0%	4.0%	*3.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	661.9	929.6	1254.5	741.0	3587.0
2021	696.5	1000.2	1308.2	798.9	3803.8
2022	783.5	1061.7	1469.9	1009.3	4324.4
2023	*790*	*1070*	*1475*	*1015*	*4350*
2024	*835*	*1130*	*1560*	*1075*	*4600*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.27	1.71	3.07	d.17	4.87
2021	.32	1.91	3.00	.24	5.47
2022	.15	1.45	2.88	d.21	4.26
2023	*.15*	*1.35*	*2.75*	*d.10*	*4.15*
2024	*.20*	*1.45*	*2.90*	*d.05*	*4.50*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.737	.738	.738	.782	3.00
2020	.783	.783	.783	.83	3.18
2021	.83	.83	.83	.85	3.34
2022	.85	.85	.85	.85	3.40
2023	.865				

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.3 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, 47%; commercial/industrial, 41%; other, 12%. Generating sources: gas, 25%; nuclear, 24%; coal, 20%; renewables, 12%; purchased, 19%. Fuel costs: 38% of revenues. '22 reported deprec. rate: 3.03%. Has 5,861 employees. Chairman, President & CEO: Jeffrey B. Guldner. 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 Capital is likely to see its profits decline in 2023. Leadership expects full-year earnings to fall within a range of $3.95 to $4.15 per share. The utility is up against a difficult 2022 comparison, which benefited from excessive heat and humidity that helped drive electric usage up 4.4% from the prior year. Additional headwinds include rising retirement contributions, as a result of the decline in equity and bond markets, and higher interest expense.

The company has an opportunity to improve upon a strained relationship with its regulatory commission. The 5-person panel received a makeover in January when two new commissioners replaced former members whose terms were up, and a new chairperson was elected. Company leadership has publicly stated its desire for a more constructive partnership.

Pinnacle's pending general rate case may help to restore some of the earnings power lost from its previous one. The late 2021 decision went very poorly. Entering calendar 2022, the utility was operating under revised regulatory parameters that cut its allowed return on equity (ROE) from 10% to a nationwide low of 8.7%. The change effectively reduced the company's annual earning power by about $1.00 per share. Pinnacle West is requesting its ROE be restored near the former level. The company is also seeking an expansion in the use of automatic pricing mechanisms to cut regulatory lag in the recoupment of investments it's planning to make in support of the state's clean-energy objectives. A decision is due in the fourth quarter. A recent appeals court decision has set a precedent for at least some progress towards higher allowable returns. A trio of Arizona appellate judges gave an opinion stating that the regulatory commission overstepped its bounds by penalizing the utility for "poor customer service," and has ruled the company can lift electric rates based on an 8.9% ROE. The panel also approved recoupment of $215 million of investments for reduced coal emissions.

This untimely issue has outperformed the *Value Line Utility Index* by 23 percentage points over the past six months. Total return prospects no longer stand out relative to the peer median.

Anthony J. Glennon *April 21, 2023*

(A) Diluted EPS. Excl. nonrec. gain/(loss): '09, ($1.45); '17, 8¢; gains/(losses) from discont. ops.: '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). '19 & '20 EPS don't sum due to rounding. Next egs. report due early May. (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/other intangibles. In '22: $17.54/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on common equity in '23: 8.9%. Regulatory Climate: Below Average.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	40
Earnings Predictability	95

PNM RESOURCES NYSE-PNM

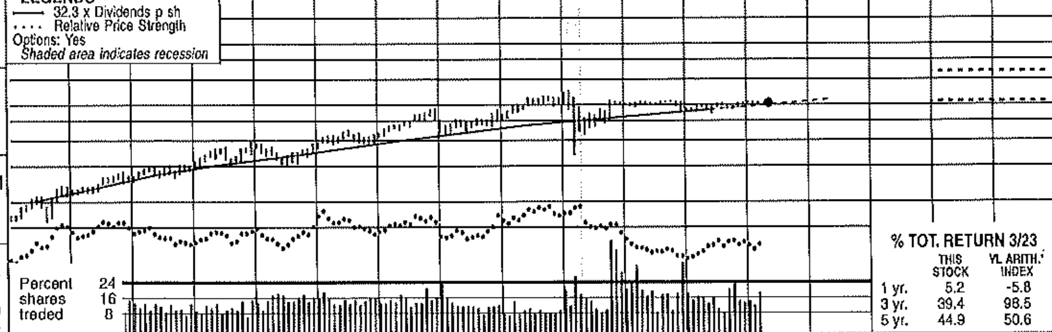
RECENT PRICE	48.98	P/E RATIO	18.8 (Trailing: 18.3; Median: 19.0)	RELATIVE P/E RATIO	1.09	DIV'D YLD	3.0%	VALUE LINE

TIMELINESS — Suspended 1/20/23
SAFETY 2 Raised 4/23/21
TECHNICAL — Suspended 1/20/23
BETA .90 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	22.5	24.5	31.6	31.2	36.2	46.0	45.3	53.0	56.1	50.1	49.3	49.6
Low:	17.3	20.1	23.5	24.4	29.2	33.3	33.8	39.7	27.1	43.8	43.4	48.4

Target Price Range 2026 | 2027 | 2028

LEGENDS
—— 32.3 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$45-$61	$53 (10%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+45%)	12%
Low	50	(Nil)	4%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	128	135	171
to Sell	115	99	110
Hld's(000)	77513	77410	75195

% TOT. RETURN 3/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.2	-5.8
3 yr.	39.4	98.5
5 yr.	44.9	50.6

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
24.92	22.65	19.01	19.31	21.35	16.85	17.42	18.03	18.07	17.11	18.14	18.04	18.30	17.74	20.74	26.21	*26.15*	*26.65*	Revenues per sh	*28.35*
2.54	1.76	2.32	2.67	3.18	3.39	3.52	4.09	4.28	4.51	5.30	5.47	5.95	5.80	6.19	6.67	*6.75*	*7.00*	"Cash Flow" per sh	*8.15*
.76	.11	.58	.87	1.08	1.31	1.41	1.45	1.48	1.46	1.92	2.00	2.16	2.28	2.45	2.69	*2.70*	*2.80*	Earnings per sh A	*3.15*
.91	.61	.50	.50	.50	.58	.68	.76	.82	.90	.99	1.09	1.18	1.25	1.33	1.41	*1.49*	*1.59*	Div'd Decl'd per sh B ■ †	*1.90*
5.94	3.99	3.32	3.25	4.10	3.88	4.37	5.78	7.01	7.53	6.28	6.29	7.74	7.91	10.89	10.63	*10.75*	*9.30*	Cap'l Spending per sh	*9.00*
22.03	18.89	18.90	17.60	19.62	20.05	20.87	22.39	20.78	21.04	21.28	21.20	21.08	23.88	25.25	25.54	*26.65*	*27.75*	Book Value per sh C	*31.55*
76.81	86.53	86.67	86.67	79.65	79.65	79.65	79.65	79.65	79.65	79.65	79.65	79.65	85.83	85.83	85.83	*88.00*	*90.00*	Common Shs Outst'g D	*90.00*
35.6	NMF	18.1	14.0	14.5	15.0	16.1	18.7	18.7	22.4	20.4	19.4	22.2	19.6	19.9	17.4	*Bold figures are*		Avg Ann'l P/E Ratio	*19.5*
1.89	NMF	1.21	.89	.91	.95	.90	.98	.94	1.18	1.03	1.05	1.18	1.01	1.08	1.01	*Value Line*		Relative P/E Ratio	*1.10*
3.4%	4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	2.8%	3.0%	2.8%	2.5%	2.8%	2.5%	2.8%	2.7%	3.0%	*estimates*		Avg Ann'l Div'd Yield	*3.1%*

CAPITAL STRUCTURE as of 12/31/22
Total Debt $4309.4 mill. Due in 5 Yrs $2262.1 mill.
LT Debt $3892.6 mill. LT Interest $132.0 mill.
(Total Interest Coverage: 3.1x)
Leases, Uncapitalized Annual rentals $19.0 mill.
Pension Assets-12/22 $454.0 mill.
Oblig $545.6 mill.
Pfd Stock $11.5 mill. **Pfd Div'd** $.5 mill.
115,293 shs. 4.58%, $100 par without mandatory redemption. Sinking fund began 2/1/84.

Common Stock 85,834,874 shs.
as of 2/17/23
MARKET CAP: $4.2 billion (Mid Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
1387.9	1435.9	1439.1	1363.0	1445.0	1436.6	1457.6	1523.0	1779.9	2249.6	*2300*	*2400*	Revenues ($mill)	*2550*
114.0	116.8	118.8	117.4	154.4	160.6	173.1	183.4	211.6	232.0	*235*	*250*	Net Profit ($mill)	*285*
31.6%	34.8%	36.9%	32.4%	33.0%	12.9%	8.1%	9.5%	13.4%	14.6%	*15.0%*	*16.0%*	Income Tax Rate	*19.0%*
1.3%	10.7%	17.0%	11.0%	11.9%	12.1%	9.8%	8.9%	8.6%	9.0%	*9.0%*	*9.0%*	AFUDC % to Net Profit	*8.0%*
50.0%	47.8%	54.1%	55.7%	56.1%	61.1%	59.8%	56.9%	61.8%	63.9%	*63.0%*	*62.5%*	Long-Term Debt Ratio	*63.0%*
49.7%	51.9%	45.5%	44.0%	43.6%	38.6%	39.9%	42.9%	38.0%	36.0%	*37.0%*	*37.5%*	Common Equity Ratio	*37.0%*
3344.0	3437.1	3633.3	3806.8	3887.5	4370.0	4207.7	4780.6	5698.6	6096.1	*6350*	*6650*	Total Capital ($mill)	*7700*
3933.9	4270.0	4535.4	4904.7	4980.2	5234.6	5466.0	5965.1	6752.9	6972.8	*7560*	*8020*	Net Plant ($mill)	*9150*
5.2%	5.1%	4.8%	4.7%	5.3%	5.0%	5.5%	4.9%	4.6%	4.9%	*4.5%*	*4.5%*	Return on Total Cap'l	*4.5%*
6.8%	6.5%	7.1%	7.0%	9.0%	9.4%	10.2%	8.9%	9.7%	10.5%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.0%*
6.8%	6.5%	7.1%	7.0%	9.1%	9.5%	10.3%	8.9%	9.7%	10.6%	*10.0%*	*10.0%*	Return on Com Equity E	*10.0%*
3.8%	3.2%	3.3%	2.8%	4.5%	4.5%	4.8%	4.1%	4.6%	5.1%	*4.5%*	*4.5%*	Retained to Com Eq	*4.0%*
45%	51%	54%	61%	51%	53%	54%	54%	53%	52%	*55%*	*57%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	NA	NA	NA
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)	1974	1968	2139
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	1.1%	1.2%	1.0%
Fixed Charge Cov. (%)	257	317	289

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	1.0%	4.0%	*4.5%*
"Cash Flow"	7.5%	6.0%	*4.5%*
Earnings	8.5%	9.0%	*4.0%*
Dividends	9.5%	8.0%	*6.0%*
Book Value	2.5%	3.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	333.6	357.6	472.5	359.3	1523.0
2021	364.7	426.5	554.6	434.1	1779.9
2022	444.1	499.7	729.9	575.9	2249.6
2023	*455*	*510*	*745*	*590*	*2300*
2024	*475*	*530*	*780*	*615*	*2400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.18	.55	1.40	.15	2.28
2021	.32	.55	1.37	.21	2.45
2022	.50	.57	1.46	.15	2.69
2023	*.43*	*.57*	*1.45*	*.25*	*2.70*
2024	*.45*	*.59*	*1.50*	*.26*	*2.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.29	.29	.29	.29	1.16
2020	.3075	.3075	.3075	.3075	1.23
2021	.3275	.3275	.3275	.3275	1.31
2022	.3475	.3475	.3475	.3475	1.39
2023	.3675				

BUSINESS: PNM Resources, Inc. is a holding company with two regulated electric utilities. Public Service Company of New Mexico (PNM) serves 544,000 customers in north central New Mexico, including Albuquerque and Sante Fe. Texas-New Mexico Power Company (TNMP) transmits and distributes power to 268,000 customers in Texas. Electric revenue breakdown: residential, 30%; commercial, 26%; industrial, 5%; other, 39%. Generating sources not available. Fuel costs: 44% of revenues. '22 reported depreciation rates: 2.6%-7.8%. Has 1,537 employees. Chairman and CEO: Patricia Vincent-Collawn. Incorporated: New Mexico. Address: 414 Silver Ave. SW, Albuquerque, New Mexico 87102-3289. Telephone: 505-241-2700. Internet: www.pnmresources.com.

A regulatory decision on PNM Resources' merger with AVANGRID, Inc. is nearing the finish line. To recap, PNM shareholders are to receive $50.30 per share in an all-cash deal. Approval was received from multiple state and federal regulatory agencies except for one. The New Mexico Public Regulation Commission (NMPRC) voted against the merger in late 2021, citing concerns over AVANGRID's track record in the Northeast, a legal investigation into the CEO of its parent company, Iberdrola of Spain, and potentially higher electric rates. In January 2022, the companies appealed the decision to the New Mexico Supreme Court. While in June, charges against the Iberdrola CEO in a corporate espionage case were dismissed. Further, the NMPRC commissioners who voted against the merger completed their term of office in December. The New Mexico governor has since made all new appointments who should be more amenable to her proactive stance on "green" energy. Moreover, AVANGRID has the clean-energy expertise needed to achieve the state's aggressive goal of 50% renewables by 2030.

The companies and the agency that had been the main obstacle to the deal have agreed to renegotiate. A joint motion has been filed with the state supreme court to dismiss the appeal and remand the case back to the NMPRC. The revamped regulatory commission has agreed to a rehearing and reconsideration to be made in a timely fashion. We suspect an agreement can be made that is based on certain guarantees of reliability and pricing restraints.

PNM Resources' Timeliness rank is suspended, as the buyout is the dominant factor now. The stock has been trading as if a consummated merger is likely. The price has moved to within 2%-4% of AVANGRID's offer and has held that level since early December. No new commitments should be made. For existing shareholders, the decision is not so clear cut. They may prefer this deal not go through, especially if the steadily growing dividend is the main draw. We suggest taking half of the position off the table. There are alternative utilities offering higher yields and solid dividend growth.

Anthony J. Glennon *April 21, 2023*

(A) Dil. EPS. Excl. nonrec. gain/(loss): '08, ($3.77); '10, ($1.36); '11, 88¢; '13, (16¢); '15, ($1.28); '17, (92¢); '18, (93¢); '19, ($1.19); '20, (13¢); '21, (18¢); '22, (72¢). Excl. disc. op. gains: '08, 42¢; '09, 78¢. Next egs. report due early May. (B) Div'ds paid mid-Feb., May, Aug., & Nov. ■ Div'd reinv. plan avail. (C) Incl. def. charges/other intang. In '22: $14.94/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in NM in '18: 9.575%; in TX in '11: 10.125%; Regulatory Climate: NM, Below Average.; TX, Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	90

PORTLAND GENERAL NYSE-POR

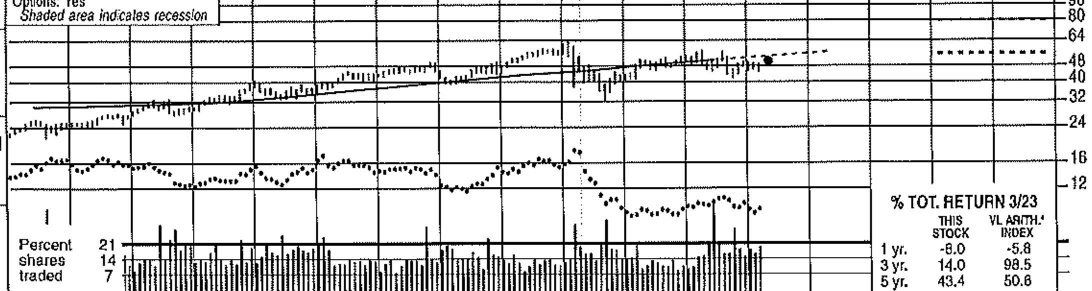
RECENT PRICE 50.66 | P/E RATIO 18.8 (Trailing: 18.5; Median: 18.0) | RELATIVE P/E RATIO 1.09 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 4 Lowered 3/10/23
SAFETY 2 Raised 10/22/21
TECHNICAL 5 Lowered 4/21/23
BETA .85 (1.00 = Market)

High:	28.1	33.3	40.3	41.0	45.2	50.1	50.4	58.4	63.1	53.1	57.0	50.7
Low:	24.3	27.4	29.0	33.0	35.3	42.4	39.0	44.0	32.0	40.8	41.6	44.7

Target Price Range 2026 | 2027 | 2028

LEGENDS
— 28.6 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$41-$68 $55 (10%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+60%)	15%
Low	55	(+10%)	6%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	181	193	207
to Sell	153	150	157
Hld's(000)	89213	87350	98265

Percent shares traded 21 / 14 / 7

% TOT. RETURN 3/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-8.0	-5.8
3 yr.	14.0	98.5
5 yr.	43.4	50.6

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
27.87	27.89	23.99	23.67	24.06	23.69	23.16	24.29	21.38	21.62	22.54	22.30	23.75	23.96	26.80	29.65	*28.55*	*28.15*	Revenues per sh	*31.00*
5.21	4.71	4.07	4.82	4.96	5.15	4.93	6.08	5.37	5.78	6.16	6.65	6.97	7.83	7.25	7.41	*7.45*	*7.80*	"Cash Flow" per sh	*9.40*
2.33	1.39	1.31	1.66	1.95	1.87	1.77	2.18	2.04	2.16	2.29	2.37	2.39	2.75	2.72	2.74	*2.70*	*3.00*	Earnings per sh A	*3.65*
.93	.97	1.01	1.04	1.06	1.08	1.10	1.12	1.18	1.26	1.34	1.43	1.52	1.59	1.70	1.79	*1.88*	*1.98*	Div'd Decl'd per sh B ■ †	*2.36*
7.28	6.12	9.25	5.97	3.98	4.01	8.40	12.87	6.73	6.57	5.77	6.67	6.78	8.76	7.11	8.58	*12.75*	*9.50*	Cap'l Spending per sh	*9.50*
21.05	21.64	20.50	21.14	22.07	22.87	23.30	24.43	25.43	26.35	27.11	28.07	28.99	29.18	30.28	31.13	*32.90*	*34.75*	Book Value per sh C	*38.70*
62.53	62.58	75.21	75.32	75.36	75.56	78.09	78.23	88.79	88.95	89.11	89.27	89.39	89.54	89.41	89.28	*94.50*	*99.50*	Common Shs Outst'g D	*100.00*
11.9	16.3	14.4	12.0	12.4	14.0	16.9	15.3	17.7	19.1	20.0	18.4	22.3	16.6	17.7	18.2	*Bold figures are*		Avg Ann'l P/E Ratio	*18.5*
.63	.98	.96	.76	.78	.89	.95	.81	.89	1.00	1.01	.99	1.19	.85	.96	1.06	*Value Line*		Relative P/E Ratio	*1.05*
3.3%	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%	3.3%	3.1%	2.9%	3.3%	2.8%	3.5%	3.5%	3.6%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 12/31/22
Total Debt $3960 mill. Due in 5 Yrs $520 mill.
LT Debt $3680 mill. LT Interest $146 mill.
Incl. $294 mill. finance leases.
(Total Interest Coverage: 2.8x)
Leases, Uncapitalized Annual rentals $4 mill.
Pension Assets-12/22 $547 mill. Oblig $695 mill.
Pfd Stock None

Common Stock 89,312,765 shs. as of 2/8/23

MARKET CAP: $4.5 billion (Mid Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
1810.0	1900.0	1898.0	1923.0	2009.0	1991.0	2123.0	2145.0	2396.0	2647.0	*2700*	*2800*	Revenues ($mill)	*3100*
137.0	175.0	172.0	193.0	204.0	212.0	214.0	247.0	244.0	245.0	*250*	*290*	Net Profit ($mill)	*365*
23.2%	26.0%	20.7%	20.6%	25.3%	7.4%	11.2%	12.4%	8.6%	15.2%	*17.5%*	*17.5%*	Income Tax Rate	*17.5%*
14.6%	33.7%	19.8%	16.6%	8.8%	8.0%	7.0%	9.7%	10.2%	8.6%	*10.0%*	*9.0%*	AFUDC % to Net Profit	*8.0%*
51.3%	52.7%	47.8%	48.4%	50.1%	46.5%	51.3%	53.6%	56.8%	57.0%	*57.0%*	*54.5%*	Long-Term Debt Ratio	*55.0%*
48.7%	47.3%	52.2%	51.6%	49.9%	53.5%	48.7%	46.4%	43.2%	43.0%	*43.0%*	*45.5%*	Common Equity Ratio	*45.0%*
3735.0	4037.0	4329.0	4544.0	4642.0	4684.0	5323.0	5628.0	6265.0	6459.0	*7200*	*7600*	Total Capital ($mill)	*8550*
4880.0	5679.0	6012.0	6434.0	6741.0	6887.0	7161.0	7539.0	8005.0	8465.0	*9200*	*9675*	Net Plant ($mill)	*10650*
5.1%	5.8%	5.4%	5.6%	5.5%	5.8%	5.1%	5.6%	4.9%	4.9%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.5%*
7.5%	9.2%	7.6%	8.2%	8.4%	8.5%	8.3%	9.5%	9.0%	8.8%	*8.0%*	*8.5%*	Return on Shr. Equity	*9.5%*
7.5%	9.2%	7.6%	8.2%	8.4%	8.5%	8.3%	9.5%	9.0%	8.8%	*8.0%*	*8.5%*	Return on Com Equity E	*9.5%*
2.9%	4.6%	3.3%	3.5%	3.6%	3.5%	3.1%	4.1%	3.5%	3.1%	*2.5%*	*3.0%*	Retained to Com Eq	*3.5%*
61%	50%	56%	57%	58%	59%	63%	57%	61%	64%	*69%*	*66%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	+.4	+5.1	+3.4
Avg. Indust. Use (MWH)	18472	20002	22097
Avg. Indust. Revs. per KWH (¢)	4.99	5.22	5.23
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3771	4447	4255
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.5	+.6	+1.1
Fixed Charge Cov. (%)	275	261	254

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	1.0%	4.0%	2.5%
"Cash Flow"	4.0%	5.5%	4.0%
Earnings	4.0%	5.0%	5.0%
Dividends	5.0%	6.0%	5.5%
Book Value	3.0%	3.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	573	469	547	556	2145
2021	609	537	642	608	2396
2022	626	591	743	687	2647
2023	*650*	*600*	*750*	*700*	*2700*
2024	*675*	*625*	*775*	*725*	*2800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.91	.43	.84	.57	2.75
2021	1.07	.36	.56	.73	2.72
2022	.67	.72	.65	.70	2.74
2023	*.65*	*.70*	*.65*	*.70*	*2.70*
2024	*.72*	*.78*	*.72*	*.78*	*3.00*

Cal-endar	QUARTERLY DIVIDENDS PAID D ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.3625	.3625	.385	.385	1.50
2020	.385	.385	.385	.4075	1.56
2021	.4075	.4075	.43	.43	1.68
2022	.43	.43	.4525	.4525	1.77
2023	.4525	.4525			

BUSINESS: Portland General Electric Company (PGE) provides electricity to 926,000 customers in 51 cities in a 4,000-square-mile area of Oregon, including Portland and Salem (population: 1.9 million). The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 52%; commercial, 33%; industrial, 14%; other, 1%. Generating sources: gas, 32%; wind, 15%; coal, 4%; hydro, 7%; purchased, 41%. Fuel costs: 37% of revenues. '22 reported depreciation rate: 3.4%. Has 2,873 full-time employees. Chairman: Jack E. Davis. President and CEO: Maria M. Pope. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, OR 97204. Tel.: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric is likely to post a decline in share earnings this year. For full-year 2023, leadership expects profits to land within a range of $2.60 to $2.75 per share. The utility is up against a difficult comparison in terms of 2022's electric usage, which was up 3.4% from the 2021 level due in part to a historically warm summer. More pressing, however, is the degree to which PGE is expanding its capital budget in anticipation of major investments in generating capacity. Capex is slated to rise over 55%, to roughly $1.2 billion in 2023. Financing costs will pressure this year's bottom line.

Profits ought to be on the mend in 2024. PGE recently filed a GRC (general rate case) with its state regulatory body. The utility is seeking a 14% price hike, in part to recoup high purchased power costs incurred last year. Most of the request is to address reliability and resiliency work, capital investments, and rising operating and financing costs. We expect a constructive outcome, with new rates to take effect beginning in January of next year.

Investments in "green" power should help to accelerate long-term earnings growth. Oregon is pursuing a very aggressive transition to renewable energy, with a target of zero greenhouse gas emissions from electric generation by 2040. Accordingly, PGE is looking to add at least 375 to 500 megawatts of renewables and "nonemitting" annual capacity in the next few years. Thus far, the company has agreed to partner with NextEra Energy (NEE) to construct a 311 mw wind energy facility. PGE will own two-thirds of the venture, and will have a 30-year contract with NEE to purchase the remaining generation. Project completion is targeted for December. The green light from regulators to pursue these types of investments should result in mid- to high-single-digit growth in the rate base (the dollar value of assets a utility is allowed to earn an economic return on) for years to come. This, along with rising demand from a vibrant tech-based local economy, should allow the company to achieve its long-term 5%-7% earnings and dividend growth targets.

PGE stock is untimely. Still, utility investors may find its 3- to 5-year total return prospects worthwhile.

Anthony J. Glennon *April 21, 2023*

(A) Diluted earnings. Excl. nonrecurring gains/(losses): '13, (42¢); '17, (19¢); '20, ($1.03); '22, (14¢). Next earnings report due April 28th.
(B) Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan available. † Shareholder investment plan available.
(C) Incl. deferred charges. In '21: $473 mill., $5.30/sh. (D) In mill.
(E) Rate base: Net original cost. Rate allowed on common equity in '22: 9.5%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	95

PPL CORPORATION NYSE-PPL

RECENT PRICE 28.77 | P/E RATIO 18.0 (Trailing: 20.5; Median: 14.0) | RELATIVE P/E RATIO 1.07 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 4 Lowered 4/21/23
SAFETY 3 Lowered 3/18/22
TECHNICAL 5 Lowered 4/21/23
BETA 1.05 (1.00 = Market)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	30.2	33.6	38.1	36.7	39.9	40.2	32.5	36.3	36.8	30.7	31.0	31.7
Low:	26.7	28.4	29.4	29.2	32.1	30.7	25.3	27.8	18.1	26.2	23.5	24.9

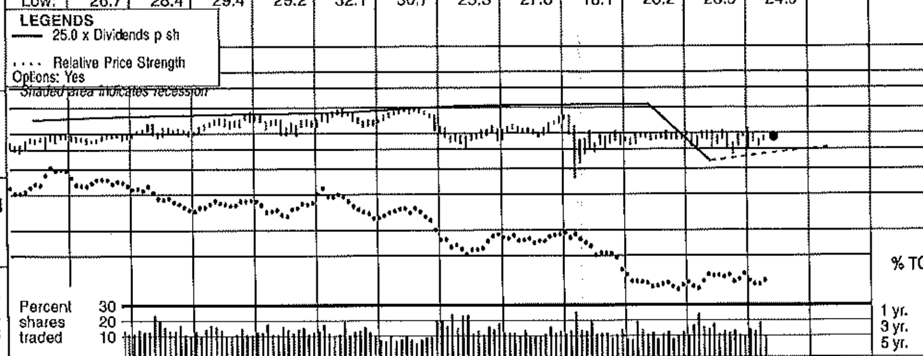
18-Month Target Price Range
Low-High: $23-$40 Midpoint (% to Mid): $32 (10%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+55%)	14%
Low	30	(+5%)	5%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	345	333	370
to Sell	380	351	358
Hld's(000)	512086	521454	529592



Target Price Range 2026 | 2027 | 2028

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.9	0.8
3 yr.	28.3	65.7
5 yr.	24.9	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB, LLC	26-28
17.41	21.47	20.03	17.63	22.02	21.11	18.82	17.27	11.38	11.06	10.74	10.81	10.13	9.89	7.87	10.73	*9.80*	*10.15*	Revenues per sh	*11.50*
5.10	4.71	3.47	3.66	4.59	4.84	4.64	4.58	3.78	4.28	3.68	4.16	3.94	3.81	2.07	3.09	*3.20*	*3.30*	"Cash Flow" per sh	*3.70*
2.63	2.45	1.19	2.29	2.81	2.61	2.38	2.38	2.37	2.79	2.11	2.58	2.37	2.04	.53	1.41	*1.60*	*1.70*	Earnings per sh A	*2.10*
1.22	1.34	1.38	1.40	1.40	1.44	1.47	1.49	1.50	1.52	1.58	1.64	1.65	1.66	1.66	.88	*.96*	*1.03*	Div'd Decl'd per sh B ■	*1.26*
4.51	3.79	3.25	3.30	4.30	5.34	6.68	6.14	5.24	4.30	4.52	4.50	4.02	4.23	2.68	2.93	*3.25*	*3.65*	Cap'l Spending per sh	*4.00*
14.88	13.55	14.57	16.98	18.72	18.01	19.78	20.47	14.72	14.56	15.52	16.18	16.93	17.39	18.67	18.89	*19.50*	*20.15*	Book Value per sh C	*22.45*
373.27	374.58	377.18	483.39	578.41	581.94	630.32	665.85	673.86	679.73	693.40	720.32	767.23	768.91	735.11	736.49	*737.00*	*737.00*	Common Shs Outst'g D	*738.00*
17.3	17.6	25.7	11.9	10.5	10.9	12.8	14.1	13.9	12.8	17.6	11.3	13.3	13.9	54.1	20.0	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.92	1.06	1.71	.76	.66	.69	.72	.74	.70	.67	.89	.61	.71	.71	2.92	1.16	*Value Line*		Relative P/E Ratio	*.95*
2.7%	3.1%	4.5%	5.1%	5.1%	5.1%	4.8%	4.4%	4.5%	4.2%	4.2%	5.6%	5.2%	5.8%	5.8%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 12/31/22
Total Debt $14228 mill. Due in 5 Yrs $3613 mill.
LT Debt $12889 mill. LT Interest $427 mill.
Incl. 23 mill. units 7.75%, $25 liq. value; 82,000 units 8.23%, $1000 face value.
(LT interest earned: 3.5x)

Leases, Uncapitalized Annual rentals $24 mill.
Pension Assets-12/22 $3149 mill. Oblig $3333 mill.

Pfd Stock None
Common Stock 736,677,854 shs. as of 1/31/23
MARKET CAP: $21.2 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
11860	11499	7669.0	7517.0	7447.0	7785.0	7769.0	7607.0	5783.0	7902.0	*7220*	*7480*	Revenues ($mill)	*8500*
1541.0	1583.0	1603.0	1902.0	1449.0	1827.0	1746.0	1571.0	401.0	1041.0	*1180*	*1255*	Net Profit ($mill)	*1550*
23.1%	33.0%	22.5%	25.4%	24.2%	20.0%	19.0%	20.3%	23.0%	19.2%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
3.7%	2.8%	1.6%	1.6%	1.9%	2.0%	1.9%	1.8%	6.0%	.7%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
62.3%	58.0%	65.2%	64.3%	64.8%	63.3%	61.5%	61.7%	43.7%	48.1%	*47.5%*	*46.5%*	Long-Term Debt Ratio	*44.0%*
37.7%	42.0%	34.8%	35.7%	35.2%	36.7%	38.5%	38.3%	56.3%	51.9%	*52.5%*	*53.5%*	Common Equity Ratio	*56.0%*
33058	32484	28482	27707	30608	31726	33712	34926	24389	26804	*27270*	*27735*	Total Capital ($mill)	*29675*
33087	34597	30382	30074	33092	34458	36482	38892	25470	30238	*31050*	*31900*	Net Plant ($mill)	*34900*
6.2%	6.5%	7.1%	8.4%	6.2%	7.2%	6.6%	5.9%	2.6%	4.9%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.5%*
12.4%	11.6%	16.2%	19.2%	13.5%	15.7%	13.4%	11.7%	2.9%	7.5%	*8.0%*	*8.5%*	Return on Shr. Equity	*9.5%*
12.4%	11.6%	16.2%	19.2%	13.5%	15.7%	13.4%	11.7%	2.9%	7.5%	*8.0%*	*8.5%*	Return on Com Equity E	*9.5%*
5.3%	4.5%	6.0%	8.8%	3.5%	6.0%	4.3%	2.2%	NMF	1.8%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
57%	61%	63%	54%	74%	62%	68%	81%	NMF	76%	*60%*	*61%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-5.2	+3.0	+1.5
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. (%)	278	154	348

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-7.5%	-3.0%	3.5%
"Cash Flow"	-3.5%	-5.0%	3.5%
Earnings	-6.0%	-11.5%	8.0%
Dividends	--	-2.0%	-1.5%
Book Value	--	4.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	2054	1739	1885	1929	7607.0
2021	1498	1288	1512	1485	5783.0
2022	1782	1696	2134	2290	7902.0
2023	*1865*	*1640*	*1960*	*1755*	*7220*
2024	*1810*	*1720*	*2150*	*1800*	*7480*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.72	.45	.50	.38	2.04
2021	.26	d.20	.27	.19	.53
2022	.41	.30	.41	.28	1.41
2023	*.43*	*.30*	*.44*	*.43*	*1.60*
2024	*.46*	*.33*	*.47*	*.44*	*1.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.41	.4125	.4125	.4125	1.65
2020	.4125	.415	.415	.415	1.66
2021	.415	.415	.415	.415	1.66
2022	.415	.20	.225	.225	1.07
2023	.225				

BUSINESS: PPL Corporation (formerly PP&L Resources, Inc.) is a holding company for PPL Electric Utilities, which distributes electricity to 1.4 mill. customers in eastern & central Pennsylvannia. Acquired Kentucky Utilities and Louisville Gas and Electric (1.3 mill. customers) 11/10. Acq'd Narragansett Electric (770,000 customers, renamed Rhode Island Energy) 5/22. Spun off power-generating sub. in '15. Sold electric distribution sub. in U.K. in '21. Electric rev. breakdown: res'l, 46%; comm'l, 21%; ind'l, 10%; other, 23%. Fuel costs: 33% of revs. '22 reported deprec. rate: 3.2%. Has 6,527 employees. Chairman: William H. Spence. President & CEO: Vincent Sorgi. Inc.: PA. Address: Two North Ninth St., Allentown, PA 18101-1179. Tel.: 800-345-3085. Internet: www.pplweb.com.

PPL Corp. is under increased scrutiny these days. Indeed, its utility operations in Pennsylvania were recently the subject of a probe into their billing practices by state regulators. The investigation was reportedly set in motion by complaints from customers who saw their electricity bills increase dramatically last December. For its part, management blamed both high energy costs (that are largely beyond PPL's control) and a technical glitch (that it readily concedes was the company's fault). As we understand it, the technical problem meant that many customer bills for the month of December were based on estimated, rather than actual, power use, the former of which proved too high, given changes in market and weather conditions. That said, the glitch has now apparently been resolved. Too, PPL has enhanced its customer service capabilities to handle inquiries about billing errors and financial assistance.

Nonetheless, the electric utility recently affirmed its positive near-term outlook. For 2023, leadership still expects PPL to earn between $1.50 and $1.65 a share, up 6%–17% from last year's adjusted tally of $1.41. Notably, results will reflect a full-year's contribution from Narragansett Electric, which PPL acquired in May, 2022 and subsequently renamed Rhode Island Energy. Earnings should also benefit from lower operating and maintenance (O&M) expense.

PPL is still targeting significant cost savings over the next few years. CEO Vincent Sorgi recently figured the utility can reduce O&M expense by $60 million through the end of 2023 and an additional $90 million by the start of 2026. A good portion of the savings is expected to come from infrastructure improvements, such as the further "hardening" of transmission assets against, among other things, adverse weather events.

Shares of PPL are now ranked 4 (Below Average) for relative year-ahead price performance, having slipped a notch on our Timeliness scale since February. As an income vehicle, the stock also falls short, compared to the yields offered by both its electric utility peers and relatively low-risk government securities. As such, we'd take a pass, for now.

Nils C. Van Liew *May 12, 2023*

(A) Dil. EPS. Excl. nonrec. gain (losses): '07, (12¢); '10, (8¢); '11, 8¢; '13, (62¢); '20, (13¢); '21, (50¢); gains (losses) on disc. ops.: '07, 19¢; '08, 3¢; '09, (10¢); '10, (4¢); '12, (1¢); '14, 23¢; '15, ($1.36); '21, ($1.94). '20 & '21 EPS don't sum due to rounding. Next egs. rept. due early Aug. (B) Div'ds paid in early Jan., April, July, & Oct. ■ Div'd reinv. plan avail. (C) Incl. intang. In '21: $3.12/sh. (D) In mill. (E) Rate base: Fair val. Rate all'd on com. eq. in PA in '16: none spec.; in KY in '19: 9.725%; earned on avg. com. eq., '21: 2.8%. Reg. Clim.: Avg.

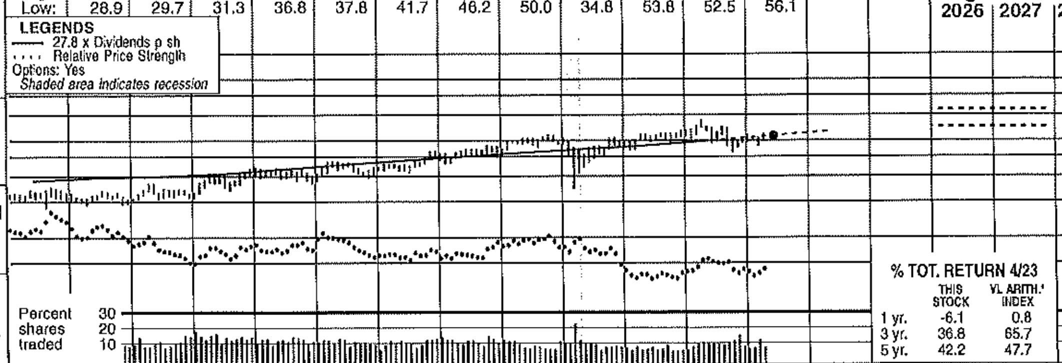
Company's Financial Strength	B++
Stock's Price Stability	80
Price Growth Persistence	15
Earnings Predictability	45

P.S. ENTERPRISE GP. NYSE-PEG

RECENT PRICE 63.14 | P/E RATIO 17.8 (Trailing: 17.9; Median: 16.0) | RELATIVE P/E RATIO 1.06 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 3 Raised 5/2/23
SAFETY 1 Raised 11/23/12
TECHNICAL 5 Lowered 3/10/23
BETA .90 (1.00 = Market)

High:	34.1	37.0	43.8	44.4	47.4	53.3	56.7	63.9	62.2	67.1	75.6	64.6		Target Price Range		
Low:	28.9	29.7	31.3	36.8	37.8	41.7	46.2	50.0	34.8	53.8	52.5	56.1		2026	2027	2028



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$51-$85 $68 (10%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+35%)	11%
Low	70	(+10%)	6%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	407	419	438
to Sell	433	363	377
Hld's(000)	354340	354404	361159

Percent shares traded 30 20 10

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-6.1	0.8
3 yr.	36.8	65.7
5 yr.	42.2	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
25.28	27.94	24.57	23.31	22.42	19.33	19.71	21.52	20.61	18.22	18.14	19.24	19.99	19.05	19.29	19.72	*23.00*	*23.60*	Revenues per sh	*25.50*
4.36	4.68	4.98	5.27	5.36	4.87	5.17	5.82	5.75	5.07	5.30	5.81	6.14	6.37	6.46	6.08	*6.25*	*6.60*	"Cash Flow" per sh	*7.75*
2.59	2.90	3.08	3.07	3.11	2.44	2.45	2.99	2.91	2.83	2.82	3.12	3.28	3.43	3.65	3.47	*3.55*	*3.75*	Earnings per sh A	*4.50*
1.17	1.29	1.33	1.37	1.37	1.42	1.44	1.48	1.56	1.64	1.72	1.80	1.88	1.96	2.04	2.16	*2.28*	*2.40*	Div'd Decl'd per sh B ■†	*2.80*
2.65	3.50	3.55	4.27	4.12	5.09	5.56	5.58	7.65	8.32	8.30	7.76	6.28	5.80	5.39	5.81	*7.20*	*7.20*	Cap'l Spending per sh	*7.25*
14.35	15.36	17.37	19.04	20.30	21.31	22.95	24.09	25.86	26.01	27.42	28.53	29.94	31.71	28.65	27.62	*28.75*	*30.10*	Book Value per sh C	*35.00*
508.52	506.02	505.99	505.97	505.95	505.89	505.86	505.84	505.28	504.87	505.00	504.00	504.00	504.00	504.00	497.00	*500.00*	*500.00*	Common Shs Outst'g D	*500.00*
16.5	13.6	10.0	10.4	10.4	12.8	13.5	12.6	14.1	15.3	16.3	16.6	18.0	15.7	16.8	18.5	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
.88	.82	.67	.66	.65	.81	.76	.66	.71	.80	.82	.90	.96	.81	.91	1.08	*Value Line*		Relative P/E Ratio	*.95*
2.7%	3.3%	4.3%	4.3%	4.2%	4.6%	4.4%	3.9%	3.8%	3.8%	3.7%	3.5%	3.2%	3.6%	3.3%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*
						9968.0	10886	10415	9198.0	9161.0	9696.0	10076	9603.0	9722.0	9800.0	*11500*	*11800*	Revenues ($mill)	*12750*
						1243.0	1518.0	1476.0	1436.0	1431.0	1582.0	1666.0	1741.0	1853.0	1739.0	*1780*	*1885*	Net Profit ($mill)	*2260*
						39.5%	38.2%	37.4%	31.7%	37.3%	23.7%	32.2%	14.3%	19.5%	13.7%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
						4.6%	4.5%	6.2%	8.4%	10.6%	8.7%	6.5%	7.0%	5.5%	5.1%	*7.0%*	*7.0%*	AFUDC % to Net Profit	*6.0%*
						40.4%	40.4%	40.3%	45.3%	46.6%	47.8%	47.7%	47.6%	51.3%	54.6%	*54.0%*	*53.5%*	Long-Term Debt Ratio	*54.0%*
						59.6%	59.6%	59.7%	54.7%	53.4%	52.2%	52.3%	52.4%	48.7%	45.4%	*46.0%*	*46.5%*	Common Equity Ratio	*46.0%*
						19470	20446	21900	24025	25915	27545	28832	30480	29657	30224	*31225*	*32250*	Total Capital ($mill)	*37800*
						21645	23589	26539	29286	31797	34363	35844	37585	34366	35942	*38250*	*40475*	Net Plant ($mill)	*46700*
						7.5%	8.4%	7.6%	6.8%	6.4%	6.7%	6.7%	6.6%	7.1%	6.7%	*6.5%*	*7.0%*	Return on Total Cap'l	*7.0%*
						10.7%	12.5%	11.3%	10.9%	10.3%	11.0%	11.0%	10.9%	12.8%	12.7%	*12.5%*	*12.5%*	Return on Shr. Equity	*13.0%*
						10.7%	12.5%	11.3%	10.9%	10.3%	11.0%	11.0%	10.9%	12.8%	12.7%	*12.5%*	*12.5%*	Return on Com Equity E	*13.0%*
						4.4%	6.3%	5.3%	4.6%	4.1%	4.7%	4.7%	4.7%	5.7%	4.8%	*4.5%*	*4.5%*	Retained to Com Eq	*5.0%*
						59%	49%	53%	58%	61%	58%	57%	57%	56%	62%	*64%*	*64%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 12/31/22
Total Debt $20270 mill. Due in 5 Yrs $7225 mill.
LT Debt $16495 mill. LT Interest $565 mill.
(Total interest coverage: 3.4x)

Leases, Uncapitalized Annual rentals $35 mill.

Pension Assets-12/22 $4911 mill. **Oblig** $5628 mill.

Pfd Stock None

Common Stock 498,769,910 shs. as of 2/17/23

MARKET CAP: $31.5 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-2.5	+1.3	+1.6
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)	9905	10064	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+.9	+.9	+.9
Fixed Charge Cov. (%)	298	273	298

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-1.0%	0.5%	4.5%
"Cash Flow"	2.0%	3.0%	3.5%
Earnings	2.0%	4.5%	4.0%
Dividends	4.0%	4.5%	5.5%
Book Value	4.0%	2.0%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	2781	2050	2370	2402	9603
2021	2889	1874	1903	3056	9722
2022	2313	2076	2272	3139	9800
2023	3755	*2100*	*2400*	*3245*	*11500*
2024	*3800*	*2175*	*2475*	*3350*	*11800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	1.03	.79	.96	.65	3.43
2021	1.28	.70	.98	.69	3.65
2022	1.33	.64	.86	.64	3.47
2023	1.39	*.65*	*.87*	*.64*	*3.55*
2024	*1.40*	*.70*	*.95*	*.70*	*3.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.47	.47	.47	.47	1.88
2020	.49	.49	.49	.49	1.96
2021	.51	.51	.51	.51	2.04
2022	.54	.54	.54	.54	2.16
2023	.57				

BUSINESS: Public Service Enterprise Group Inc. is a holding company for Public Service Electric and Gas Company (PSE&G), which serves 2.3 million electric and 1.9 million gas customers in NJ, and PSEG Power LLC, a nonregulated power generator with nuclear plants in the Northeast (sold its fossil-fuel generation, 2/22). In mid-2022, announced intent to divest offshore wind assets. Percentage of electric sales: Commercial (57%); Residential (34%); Industrial (9%). Fuel costs: 41% of revenues. '22 reported depreciation rates (utility): 1.9%-2.6%. Has 12,525 employees. Executive Chair: Dr. Ralph Izzo. Chair, Pres. & CEO: Ralph A. LaRossa. Inc.: New Jersey. Address: 80 Park Plaza, P.O. Box 1171, Newark, New Jersey 07101-1171. Tel.: 973-430-7000. Internet: www.pseg.com.

Public Service Enterprise Group (PSEG) is off to a good start in 2023, but lackluster full-year profit gains are likely. March-period earnings exceeded the consensus estimate by $0.14 per share, mainly due to an uptick in the performance of the Nuclear segment, which is the only significant business outside of the regulatory pricing umbrella. High price realizations from hedges won't be available in future quarters so the $0.08-per-share bump to the bottom line was a one-off item. PSEG still has some significant headwinds this year from the impact of higher interest rates and increased retirement contributions.

The company's long-term earnings growth target of 5%-7% should be achieved in 2024. Utility income is rising due to regulatory mechanisms that allow for near contemporaneous returns on capital used for certain grid improvements. Meanwhile, interest expense and pension costs should moderate, and management is working hard to drive efficiencies and reduce operating expenses.

New Jersey's recently announced acceleration to 100% "clean" energy by 2035 should be a boon for PSEG. We expect no shortage of state authorized infrastructure and grid-modernization projects, which generate a 9.6% regulated return on capital employed by way of rising electric delivery rates. The tenets of last year's Inflation Reduction Act (IRA) are expected to bolster the nation's transition to renewable energy over the next two decades and make it less painful for consumers. The IRA also provides incentives that will help keep PSEG's nuclear fleet economically viable for years to come.

Public Service Enterprise stock, however, does not stand out at the recent quotation. PSEG's 3- to 5-year annual total return prospects are roughly in line with the electric utility median of 8.6%. The dividend yield is only marginally above the peer average, although the long-term rate of growth for the disbursement is perhaps 50 basis points in excess of the industry's 4.8% rate. Following a roughly 10% drawdown in value, this high-quality issue would likely be a worthwhile holding for conservative accounts seeking "plain vanilla" utility exposure.

Anthony J. Glennon *May 12, 2023*

(A) Diluted EPS. Excl. nonrec. gains/(losses): '08, (96¢); '09, 6¢; '11, (34¢); '12, 7¢; '15, 39¢; '16, ($1.08); '17, 28¢ (net); '18, (29¢); '19, 5¢; '20, 33¢; '21, ($4.94); '22, ($1.41); Q1 '23, $1.19; disc. ops.: '07, 3¢; '08, 40¢; '10, 1¢; '11, 19¢. Next egs. report due early August.
(B) Div'ds historically paid in late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail.
(C) Incl. intang. In '22: $8.90/sh.
(D) In mill., adj. for '08 split. (E) Rate base: Net original cost. Rate allowed on common equity in '18: 9.6%; Regulatory Climate: Average.

Company's Financial Strength	A++
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	100

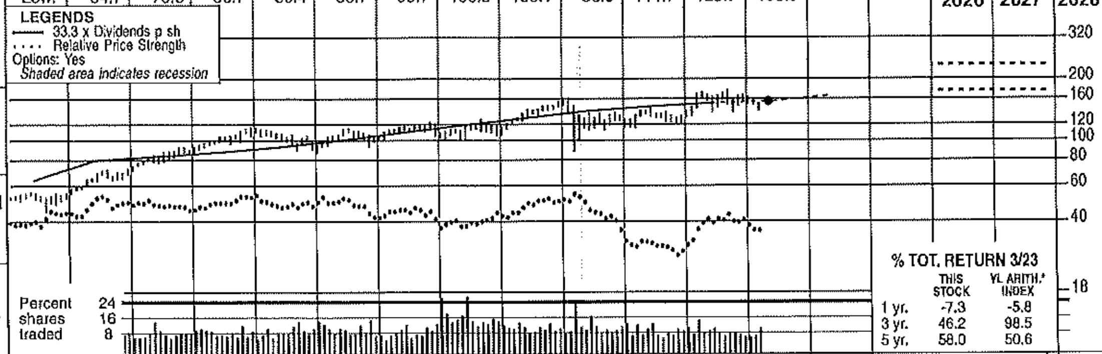
SEMPRA ENERGY NYSE-SRE

RECENT PRICE 155.29 | P/E RATIO 17.4 (Trailing: 16.9; Median: 20.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 3 Lowered 4/21/23
SAFETY 2 Raised 7/29/16
TECHNICAL 3 Lowered 4/21/23
BETA .95 (1.00 = Market)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	72.9	93.0	116.3	116.2	114.7	123.0	127.2	154.5	161.9	144.9	176.5	163.6
Low:	54.7	70.6	86.7	89.4	86.7	99.7	100.5	106.1	88.0	114.7	129.7	138.6

LEGENDS
— 33.3 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$126-$197 $162 (5%)

Target Price Range 2026 | 2027 | 2028

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	235	(+50%)	13%
Low	175	(+15%)	6%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	441	476	518
to Sell	376	332	364
Hld's(000)	268609	267683	273687

Percent shares traded 24 16 8

% TOT. RETURN 3/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-7.3	-5.8
3 yr.	46.2	98.5
5 yr.	58.0	50.6

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
43.79	44.21	32.88	37.44	41.83	39.80	43.18	44.60	41.20	40.71	44.59	42.69	37.12	39.41	40.57	45.94	*49.20*	*52.45*	Revenues per sh	*61.65*
6.93	7.40	7.94	7.76	8.58	8.92	8.87	9.41	10.32	9.50	10.57	11.07	11.14	13.22	14.17	15.70	*16.25*	*17.30*	"Cash Flow" per sh	*21.65*
4.26	4.43	4.78	4.02	4.47	4.35	4.22	4.63	5.23	4.24	4.63	5.48	5.97	7.38	8.43	9.21	*9.00*	*9.60*	Earnings per sh A	*12.00*
1.24	1.37	1.56	1.56	1.92	2.40	2.52	2.64	2.80	3.02	3.29	3.58	3.87	4.18	4.40	4.58	*4.76*	*5.00*	Div'd Decl'd per sh B ■	*6.10*
7.70	8.47	7.76	8.58	11.85	12.20	10.52	12.68	12.71	16.85	15.71	13.82	12.71	16.21	15.82	17.04	*17.00*	*17.00*	Cap'l Spending per sh	*17.00*
31.87	32.75	36.54	37.54	41.00	42.42	45.03	45.98	47.56	51.77	50.41	54.35	60.58	70.11	79.17	83.43	*85.55*	*90.20*	Book Value per sh C	*105.55*
261.21	243.32	246.51	240.45	239.93	242.37	244.46	246.33	248.30	250.15	251.36	273.77	291.71	288.47	316.92	314.33	*305.00*	*305.00*	Common Shs Outst'g D	*300.00*
14.0	11.8	10.1	12.6	11.8	14.9	19.7	21.9	19.7	24.4	24.3	20.4	22.5	17.5	15.4	16.8	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.74	.71	.67	.80	.74	.95	1.11	1.15	.99	1.28	1.22	1.10	1.20	.90	.83	.98	*Value Line*		Relative P/E Ratio	*.95*
2.1%	2.6%	3.2%	3.1%	3.6%	3.7%	3.0%	2.6%	2.7%	2.9%	2.9%	3.2%	2.9%	3.2%	3.4%	3.0%	*estimates*		Avg Ann'l Div'd Yield	*3.0%*

CAPITAL STRUCTURE as of 12/31/22
Total Debt $28919 mill. Due in 5 Yrs $6475 mill.
LT Debt $24548 mill. LT Interest $1155 mill.
Incl. $1343 mill. finance leases.
(Total Interest Coverage: 3.6x)

Leases, Uncapitalized Annual rentals $53 mill.
Pension Assets-12/22 $2390 mill. Oblig $2806 mill.
Pfd Stock $889 mill. Pfd Div'd $45 mill.
900,000 shs. 4.875%, cumulative.
Common Stock 314,569,519 shs.
as of 2/21/23
MARKET CAP: $48.8 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
10557	11035	10231	10183	11207	11687	10829	11370	12857	14439	*15000*	*16000*	Revenues ($mill)	*18500*
1060.0	1162.0	1314.0	1065.0	1169.0	1607.0	1825.0	2316.0	2701.0	2960.0	*2840*	*2985*	Net Profit ($mill)	*3655*
26.5%	19.7%	19.2%	14.4%	24.5%	20.1%	17.9%	18.0%	25.5%	20.1%	*19.0%*	*19.0%*	Income Tax Rate	*19.0%*
11.2%	14.4%	15.3%	22.2%	21.9%	12.6%	10.0%	8.7%	8.0%	8.6%	*9.0%*	*8.0%*	AFUDC % to Net Profit	*8.0%*
50.5%	51.7%	52.6%	52.7%	56.4%	55.7%	51.0%	48.2%	44.8%	47.5%	*50.5%*	*50.5%*	Long-Term Debt Ratio	*49.0%*
49.4%	48.2%	47.3%	47.3%	43.5%	38.4%	43.4%	44.8%	53.3%	50.7%	*48.0%*	*48.0%*	Common Equity Ratio	*49.5%*
22281	23513	24963	27400	29135	38769	40734	45174	47069	51683	*54700*	*57550*	Total Capital ($mill)	*63800*
25460	25902	28039	32931	36503	36796	36452	40003	43894	47782	*50800*	*53650*	Net Plant ($mill)	*60700*
6.0%	6.1%	6.4%	5.0%	5.1%	5.1%	5.5%	6.1%	6.6%	6.8%	*6.0%*	*6.0%*	Return on Total Cap'l	*7.0%*
9.6%	10.2%	11.1%	8.2%	9.2%	9.4%	9.1%	9.9%	10.4%	10.9%	*10.5%*	*10.5%*	Return on Shr. Equity	*11.0%*
9.6%	10.3%	11.1%	8.2%	9.2%	10.0%	9.5%	10.6%	10.5%	11.1%	*10.5%*	*10.5%*	Return on Com Equity E	*11.5%*
4.1%	5.0%	5.8%	2.9%	3.3%	4.1%	3.9%	4.8%	5.2%	5.7%	*5.0%*	*5.0%*	Retained to Com Eq	*5.5%*
58%	52%	48%	65%	65%	62%	62%	58%	52%	50%	*53%*	*53%*	All Div'ds to Net Prof	*51%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-.4	-3.7	+2.8
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)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.8	+.9	+.5
Fixed Charge Cov. (%)	178	201	232

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	0.5%	- -	6.5%
"Cash Flow"	5.5%	7.0%	6.5%
Earnings	7.0%	12.0%	6.0%
Dividends	8.5%	7.5%	5.5%
Book Value	7.0%	9.0%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	3029	2526	2644	3171	11370
2021	3259	2741	3013	3844	12857
2022	3820	3547	3617	3455	14439
2023	*3925*	*3575*	*3650*	*3850*	*15000*
2024	*4175*	*3825*	*3900*	*4100*	*16000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	2.53	1.58	1.31	1.88	7.38
2021	2.95	1.63	1.70	2.16	8.43
2022	2.91	1.98	1.97	2.35	9.21
2023	*2.90*	*1.80*	*1.90*	*2.40*	*9.00*
2024	*3.10*	*1.90*	*2.05*	*2.55*	*9.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.895	.9675	.9675	.9675	3.80
2020	.9675	1.045	1.045	1.045	4.10
2021	1.045	1.10	1.10	1.10	4.35
2022	1.10	1.145	1.145	1.145	4.54
2023	1.145	1.19			

BUSINESS: Sempra Energy is a holding company for San Diego Gas & Electric (SDG&E), which sells electricity & gas mainly in San Diego County, & Southern California Gas (SoCalGas), which distributes gas to most of Southern California. Owns 80% of Oncor (acq'd 3/18), which distributes electricity in Texas. Customers: 5.2 million electric, 7.0 million gas. Electric revenue breakdown not available. Purchases 76% of its power; the rest is gas. Has non-utility subsidiaries, incl. IEnova in Mexico. Sold South American utilities in 2020. Power costs: 24.5% of revenues. '22 reported deprec. rates: 2.6%-7.0%. Has 15,785 employees. Chairman, President & CEO: Jeffrey W. Martin. Inc.: CA. Address: 488 8th Ave., San Diego, CA 92101. Tel.: 619-696-2000. Internet: www.sempra.com.

Sempra Energy will likely post flat to down earnings in 2023. Leadership's projected earnings range for this year is $8.60 to $9.20 per share. Sempra is up against a difficult 2022 comparison. The final bottom-line tally for the year was a 9% gain versus 2021, and $0.51 per share above the high end of Sempra's targeted range at the start of 2022. A heat wave in southern California was a key factor, driving electricity usage up 2.8% last year. Further, the company has been making significant investments in its infrastructure and there is a degree of regulatory lag taking place. This is par for the course in this industry, but with inflation and interest rates up, delays in the recoupment of invested capital are a more onerous issue.

We expect growth will resume next year. Sempra has general rate cases filed with its regulators in Texas and California. A decision is due prior to the close of the second quarter for Oncor, the company's 80%-owned transmission and distribution subsidiary in Texas. The higher delivery rates expected for Oncor should benefit the back half of 2023, with further incremental improvement coming in 2024. Meantime, a regulatory decision is expected in the second quarter of next year for San Diego Gas & Electric and SoCalGas. Higher rates in California should be retroactive to the beginning of 2024.

The economics of the liquefied natural gas (LNG) export operation looks very attractive. Sempra Infrastructure Partners, a 70%-owned subsidiary, has done the legwork necessary to put together a project that will export 13 million tonnes per annum of LNG to Europe and Asia starting in 2027. Long-term contracts are already more than 80% subscribed to. ConocoPhillips has come on board as a partner, and KKR will also help finance the $13 billion endeavor. Sempra is expected to retain about a 20% stake, but will only have to put up a half-share of the capital. We estimate a bump in annual earnings power of $0.50-$0.75 per share, plus an opportunity to replicate the gains through additional project phases.

At the recent quote, this issue's total return prospects do not stand out relative to industry peers. We advise utility investors enter on a pullback.

Anthony J. Glennon *April 21, 2023*

(A) Dil. egs. Excl. nonrec. gain/(loss): '09, (26¢); '10, ($1.04); '11, $1.15; '12, (87¢); '13, (21¢); '15, 14¢; '16, $1.22; '17, ($3.62); '18, ($2.06); '19, 16¢; '20, (80¢); '21, ($4.42); '22, ($1.64); disc. ops.: '07, (10¢); '19, $1.16; '20, $6.30. EPS may not sum due to chg. in shs. Next egs. report due early May. (B) Div'ds paid mid-Jan., Apr., July, Oct. ■ Div'd reinv. avail. (C) Incl. intang. in '22: $14.42/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq.: SDG&E in '22: 9.95%; SoCalGas in '22: 9.8%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	55
Earnings Predictability	90

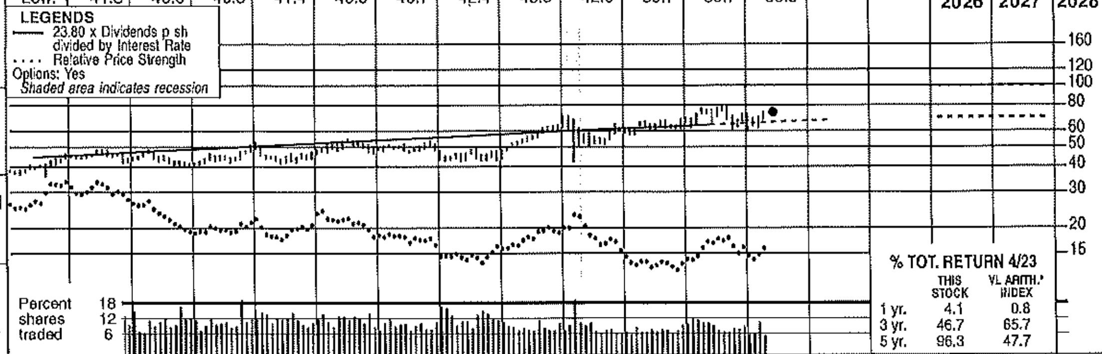
SOUTHERN COMPANY NYSE-SO

RECENT PRICE 74.09 | P/E RATIO 20.3 (Trailing: 21.6; Median: 17.0) | RELATIVE P/E RATIO 1.21 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 4 Raised 5/12/23
SAFETY 2 Lowered 2/21/14
TECHNICAL 4 Raised 5/12/23
BETA .90 (1.00 = Market)

High:	48.6	48.7	51.3	53.2	54.6	53.5	49.4	64.3	71.1	68.9	80.6	74.6
Low:	41.8	40.0	40.3	41.4	46.0	46.7	42.4	43.3	42.0	56.7	60.7	58.8

Target Price Range 2026 | 2027 | 2028



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$62-$102	$82 (10%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+35%)	11%
Low	70	(-5%)	3%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	774	781	911
to Sell	650	634	594
Hld's(000)	662355	675410	693302

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.1	0.8
3 yr.	46.7	65.7
5 yr.	96.3	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
20.12	22.04	19.21	20.70	20.41	19.06	19.26	20.34	19.18	20.09	22.86	22.73	20.34	19.29	21.80	26.89	*24.85*	*25.25*	Revenues per sh	*28.90*
4.22	4.43	4.43	4.51	4.91	5.18	5.27	5.28	5.47	5.69	6.64	6.41	6.33	6.98	7.20	7.34	*7.65*	*8.00*	"Cash Flow" per sh	*9.25*
2.28	2.25	2.32	2.36	2.55	2.67	2.70	2.77	2.84	2.83	3.21	3.00	3.17	3.25	3.42	3.61	*3.65*	*4.00*	Earnings per sh A	*5.15*
1.60	1.66	1.73	1.80	1.87	1.94	2.01	2.08	2.15	2.22	2.30	2.38	2.46	2.54	2.62	2.70	*2.78*	*2.86*	Div'd Decl'd per sh B ■	*3.10*
4.65	5.10	5.70	4.85	5.23	5.54	6.16	6.58	6.22	7.38	7.37	7.74	7.17	7.04	6.83	*7.55*	*7.85*	*7.85*	Cap'l Spending per sh	*7.50*
16.23	17.08	18.15	19.21	20.32	21.09	21.43	21.98	22.59	25.00	23.98	23.92	26.11	26.48	26.30	27.93	*28.00*	*29.90*	Book Value per sh C	*32.25*
763.10	777.19	819.65	843.34	865.13	867.77	887.09	907.78	911.72	990.39	1007.6	1033.8	1053.3	1056.5	1060.0	1089.0	*1070.0*	*1070.0*	Common Shs Outst'g D	*1070.0*
16.0	16.1	13.5	14.9	15.8	17.0	16.2	16.0	15.8	17.8	15.5	15.1	17.6	17.9	18.4	19.6	*Bold figures are*		Avg Ann'l P/E Ratio	*16.5*
.85	.97	.90	.95	.99	1.08	.91	.84	.80	.93	.78	.82	.94	.92	1.00	1.14	*Value Line*		Relative P/E Ratio	*.90*
4.4%	4.6%	5.5%	5.1%	4.6%	4.3%	4.6%	4.7%	4.8%	4.4%	4.6%	5.3%	4.4%	4.4%	4.2%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 3/31/23
Total Debt $55066 mill. **Due in 5 Yrs** $15427 mill.
LT Debt $50427 mill. **LT Interest** $1754 mill.
Incl. $215 mill. finance leases.
(LT interest earned: 3.3x)
Leases, Uncapitalized Annual rentals $307 mill.
Pension Assets-12/22 $17225 mill.
Oblig $16382 mill.
Pfd Stock $242 mill. **Pfd Div'd** $15 mill.
Incl. 10 mill. shs. 5.83% cum. pfd. ($25 stated value); 475,115 shs. 4.2%-5.44% cum. pfd. ($100 par).
Common Stock 1,090,402,540 shs.
MARKET CAP: $80.8 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
17087	18467	17489	19896	23031	23495	21419	20375	23113	29279	*26600*	*27500*	Revenues ($mill)	*30900*
2439.0	2567.0	2647.0	2757.0	3269.0	3096.0	3354.0	3481.0	3670.0	3931.3	*3960*	*4280*	Net Profit ($mill)	*5510*
34.8%	33.8%	33.4%	28.5%	25.2%	21.3%	15.9%	14.3%	16.3%	18.8%	*15.0%*	*15.0%*	Income Tax Rate	*15.0%*
11.6%	13.9%	13.2%	11.9%	7.6%	6.8%	6.0%	6.6%	7.7%	8.0%	*8.0%*	*8.0%*	AFUDC % to Net Profit	*6.0%*
51.5%	49.5%	52.8%	61.5%	64.5%	62.0%	60.1%	61.5%	64.0%	*63.5%*	*64.0%*	*64.0%*	Long-Term Debt Ratio	*63.0%*
45.8%	47.3%	44.0%	35.7%	35.0%	37.6%	39.5%	38.1%	35.6%	*36.0%*	*36.0%*	*36.0%*	Common Equity Ratio	*37.0%*
41483	42142	46788	69359	68953	65750	69594	73336	78285	*80550*	*83500*	*85000*	Total Capital ($mill)	*93500*
51208	54868	61114	78446	79872	80797	83080	87634	91108	94570	*99350*	*100000*	Net Plant ($mill)	*110000*
6.8%	7.1%	6.6%	4.9%	5.9%	5.9%	6.0%	5.9%	5.8%	5.5%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.5%*
12.1%	12.1%	12.0%	10.3%	13.3%	12.4%	12.1%	12.3%	13.0%	12.5%	*13.0%*	*13.0%*	Return on Shr. Equity	*14.5%*
12.5%	12.5%	12.6%	11.0%	13.4%	12.5%	12.1%	12.4%	13.1%	13.0%	*13.0%*	*13.0%*	Return on Com Equity E	*14.5%*
3.2%	3.2%	3.1%	2.5%	3.9%	2.6%	2.8%	2.8%	3.1%	3.0%	*3.5%*	*3.5%*	Retained to Com Eq	*5.0%*
75%	75%	76%	78%	72%	79%	77%	78%	76%	78%	*77%*	*77%*	All Div'ds to Net Prof	*67%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-8.5	-5.3	+2.0
Avg. Indust. Use (MWH)	2947	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.03	NA	NA
Capacity at Yearend (Mw)	41940	NA	NA
Peak Load, Summer (Mw)	34209	NA	NA
Annual Load Factor (%)	60.3	NA	NA
% Change Customers (yr-end)	-8.9	+1.3	+1.5
Fixed Charge Cov. (%)	281	270	275

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	--	.5%	6.0%
"Cash Flow"	4.0%	4.5%	5.0%
Earnings	3.0%	3.0%	6.5%
Dividends	3.5%	3.5%	3.5%
Book Value	3.0%	2.5%	3.5%

Cal-endar	QUARTERLY REVENUES (mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	5018	4620	5620	5117	20375
2021	5910	5198	6238	5767	23113
2022	6648	7206	8378	7047	29279
2023	6480	*6800*	*7120*	*6200*	*26600*
2024	*6800*	*7000*	*7200*	*6500*	*27500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.81	.75	1.18	.51	3.25
2021	1.09	.67	1.22	.44	3.42
2022	.97	1.07	1.31	.26	3.61
2023	.79	*.95*	*1.36*	*.55*	*3.65*
2024	*1.20*	*1.00*	*1.30*	*.50*	*4.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.60	.62	.62	.62	2.46
2020	.62	.64	.64	.64	2.54
2021	.64	.66	.66	.66	2.62
2022	.66	.68	.68	.68	2.70
2023	.68	.70			

BUSINESS: The Southern Company, through its subsidiaries, supplies electricity to 4.4 mill. customers in GA, AL, and MS. Also has a competitive generation business. Acq'd AGL Resources (renamed Southern Company Gas, 4.4 mill. customers in GA, NJ, IL, VA, & TN) 7/16. Sold Gulf Power 1/19. Electric revenue breakdown: residential, 37%; commercial, 30%; industrial, 19%; other, 14%. Generating sources: gas, 44%; coal, 20%; nuclear, 16%; other, 11%; purchased, 9%. Fuel costs: 29% of revenues. '21 reported deprec. rates (utility): 2.7%-3.6%. Has 27,300 employees. Chairman, President and CEO: Thomas A. Fanning. Inc.: Delaware. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, Georgia 30308. Tel.: 404-506-0747. Internet: www.southerncompany.com.

Southern Company's Georgia Power subsidiary is making progress and expects to complete unit 3 of the Vogtle nuclear station in May or June. In March, Unit 3 achieved initial criticality and successfully synced to the grid, which is a key step towards completion. Meanwhile, the utility anticipates that unit 4 of the Vogtle Station will be in-service by the end of the year or in the first quarter of 2024. The project will benefit the company's transition towards cleaner energy and being carbon-free as well as provide long-term dividend and profit growth. The utilities should also continue to benefit from rate relief and volume growth, and we look for earnings to advance slightly in the next few years.

Our 2023 estimate, is at the high-end of management's guidance range of $3.55-$3.65. The company started the year by posting first quarter profits of $0.79 per share, which slightly exceeded our expectations. We believe earnings growth will likely accelerate even more once the nuclear units are completed. Accordingly, we look for full-year 2024 profits of $4.00 per share. Higher retail pricing, increased usage of electricity and rate relief should also boost the bottom line over that interim. Too, management remains committed to its long-term earnings-per-share growth target of 5%-7%.

The board of directors recently raised the dividend. The increase was $0.02 a share, making the quarterly dividend $0.70 per share. The dividend has been raised in 22 consecutive years.

The stock's dividend yield of 3.8%, which sits above the utility average of approximately 3.7%, remains its most notable feature. Investors in this company should also be reassured that the utility's operations are able to weather a veritable plethora of adverse conditions. As a result, the company holds high marks for Earnings Predictability and Price Stability. The stock has increased nearly 10% in value since our last report three months ago. After the strong price run, this equity now trades within our 3-to 5-year Target Price Range. Indeed, capital appreciation potential over the next 18 months and 3 to 5 years does not stand out compared to the *Value Line* median.

Zachary J. Hodgkinson *May 12, 2023*

(A) Diluted EPS. Excl. nonrec. gain (losses): '09, (25¢); '13, (83¢); '14, (59¢); '15, (25¢); '16, (28¢); '17, ($2.37); '16, (78¢); '19, $1.30; '20, (17¢); '21, (54¢). Next earnings report due in late July. (B) Div'ds paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. def'd charges. In '22: $19.85/sh. (D) In mill. (E) Rate base: AL, MS, fair value; FL, GA, orig. cost. Allowed return on common eq. (blended): 12.5%; earned on avg. com. eq., '21: 12.8%. Regulatory Climate: GA, AL Above Average; MS, FL Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	50
Earnings Predictability	95

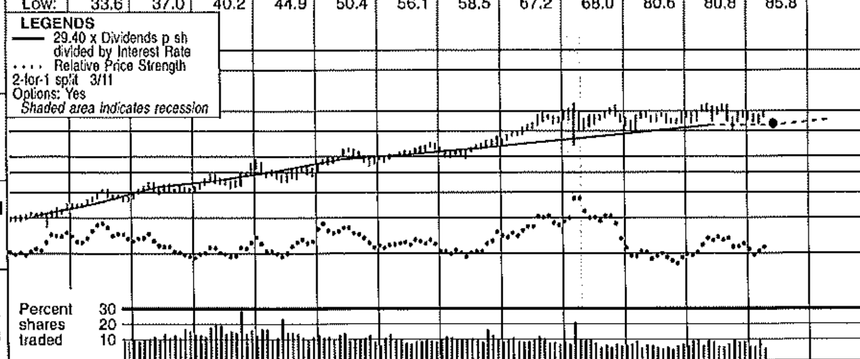
WEC ENERGY GROUP NYSE-WEC

RECENT PRICE	86.90	P/E RATIO	18.9 (Trailing: 20.3; Median: 21.0)	RELATIVE P/E RATIO	1.15	DIV'D YLD	3.6%	VALUE LINE

TIMELINESS 3 Raised 4/28/23
SAFETY 1 Raised 3/23/12
TECHNICAL 2 Raised 6/9/23
BETA .80 (1.00 = Market)

High:	41.5	45.0	55.4	58.0	66.1	70.1	75.5	98.2	109.5	99.9	108.4	99.3	
Low:	33.6	37.0	40.2	44.9	50.4	56.1	58.5	67.2	68.0	80.6	80.8	85.8	

LEGENDS
— 29.40 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 3/11
Options: Yes
Shaded area indicates recession



Target Price Range 2026 | 2027 | 2028

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$77-$129	$103 (20%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	135	(+55%)	14%
Low	110	(+25%)	9%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	490	439	477
to Sell	340	385	408
Hld's(000)	237581	235657	240294

Percent shares traded 30 20 10

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.9	0.8
3 yr.	16.0	65.7
5 yr.	72.4	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
18.12	18.95	17.65	17.98	19.46	18.54	20.00	22.16	18.77	23.68	24.24	24.34	23.85	22.96	26.36	30.43	*30.45*	*31.70*	Revenues per sh	*34.10*
2.98	2.95	3.11	3.30	3.68	4.01	4.33	4.47	3.87	5.39	5.69	6.04	6.53	6.90	7.53	8.01	*8.60*	*9.05*	"Cash Flow" per sh	*10.65*
1.42	1.52	1.60	1.92	2.18	2.35	2.51	2.59	2.34	2.96	3.14	3.34	3.58	3.79	4.11	4.46	*4.60*	*4.90*	Earnings per sh A	*5.90*
.50	.54	.68	.80	1.04	1.20	1.45	1.56	1.74	1.98	2.08	2.21	2.36	2.53	2.71	2.91	*3.12*	*3.33*	Div'd Decl'd per sh B ■	*3.80*
5.28	4.86	3.50	3.41	3.60	3.09	3.04	3.26	4.01	4.51	6.21	6.71	7.17	7.10	7.14	7.34	*9.30*	*9.30*	Cap'l Spending per sh	*9.25*
13.25	14.27	15.26	16.26	17.20	18.05	18.73	19.60	27.42	28.29	29.98	31.02	32.06	33.19	34.60	36.76	*37.35*	*37.90*	Book Value per sh C	*42.00*
233.89	233.84	233.82	233.77	230.49	229.04	225.96	225.52	315.68	315.62	315.57	315.52	315.43	315.43	315.43	315.43	*315.43*	*315.43*	Common Shs Outst'g D	*315.43*
16.5	14.8	13.3	14.0	14.2	15.8	16.5	17.7	21.3	19.9	20.0	19.6	23.5	24.9	22.3	21.9	*Bold figures are*		Avg Ann'l P/E Ratio	*20.5*
.88	.89	.89	.89	.89	1.01	.93	.93	1.07	1.04	1.01	1.06	1.25	1.28	1.21	1.27	*Value Line*		Relative P/E Ratio	*1.15*
2.1%	2.4%	3.2%	3.0%	3.3%	3.2%	3.5%	3.4%	3.5%	3.4%	3.3%	3.4%	2.8%	2.7%	3.0%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 3/31/23
Total Debt $17896.7 mill. Due in 5 Yrs $4611.7 mill.
LT Debt $15827.3 mill. LT Interest $452.7 mill.
Incl. $12.1 mill. finance leases.
(LT interest earned: 4.4x)
Leases, Uncapitalized Annual rentals $6.8 mill.
Oblig $3136.6 mill.
Pfd Stock $30.4 mill. **Pfd Div'd** $1.2 mill.
260,000 shs. 3.60%, $100 par, callable $101;
44,498 shs. 6%, $100 par.
Common Stock 315,434,531 shs.

MARKET CAP: $27.4 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
4519.0	4997.1	5926.1	7472.3	7648.5	7679.5	7523.1	7241.7	8316.0	9597.4	*9600*	*10000*	Revenues ($mill)	*10750*
578.6	589.5	640.3	940.2	998.2	1060.5	1134.2	1201.1	1301.5	1406.8	*1450*	*1545*	Net Profit ($mill)	*1860*
36.9%	38.0%	40.4%	37.6%	37.2%	13.8%	9.9%	15.9%	13.4%	18.6%	*19.0%*	*19.0%*	Income Tax Rate	*19.0%*
4.5%	1.3%	4.5%	3.8%	1.6%	2.1%	1.8%	2.4%	1.9%	2.1%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
50.6%	48.5%	51.2%	50.5%	48.0%	50.4%	52.5%	52.8%	55.3%	54.7%	*55.0%*	*55.0%*	Long-Term Debt Ratio	*55.5%*
49.1%	51.2%	48.6%	49.3%	51.9%	49.4%	47.4%	47.1%	44.6%	44.4%	*44.5%*	*44.5%*	Common Equity Ratio	*44.5%*
8626.6	8636.5	17809	18118	18238	19813	21355	22228	24467	25368	*26375*	*2700*	Total Capital ($mill)	*29800*
10907	11258	19190	19916	21347	22001	23620	25707	26982	29114	*30500*	*3100*	Net Plant ($mill)	*35100*
8.1%	8.1%	4.5%	6.3%	6.6%	6.5%	6.5%	6.5%	6.3%	6.4%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
13.6%	13.2%	7.4%	10.5%	10.5%	10.8%	11.2%	11.4%	11.9%	12.0%	*12.5%*	*12.5%*	Return on Shr. Equity	*13.0%*
13.6%	13.3%	7.4%	10.5%	10.5%	10.8%	11.2%	11.5%	11.9%	12.5%	*12.5%*	*12.5%*	Return on Com Equity E	*13.0%*
5.9%	5.3%	2.1%	3.5%	3.6%	3.7%	3.8%	3.8%	4.1%	4.0%	*4.5%*	*4.0%*	Retained to Com Eq	*4.0%*
57%	60%	71%	67%	66%	66%	66%	67%	66%	65%	*68%*	*68%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.5	-2.6	+3.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.25	6.61	7.51
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.7	+.2
Fixed Charge Cov. (%)	300	338	357

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	3.0%	2.0%	5.0%
"Cash Flow"	7.0%	7.5%	6.5%
Earnings	6.5%	7.0%	6.0%
Dividends	10.0%	6.5%	7.0%
Book Value	7.0%	3.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	2108	1548	1651	1933	7241.7
2021	2691	1676	1746	2201	8316.0
2022	2908	2127	2003	2558	9597.4
2023	2888	*2200*	*2150*	*2362*	*9600*
2024	*3000*	*2250*	*2200*	*2550*	*10000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	1.43	.76	.84	.76	3.79
2021	1.61	.87	.92	.71	4.11
2022	1.79	.91	.96	.80	4.46
2023	1.61	*1.00*	*1.14*	*.85*	*4.60*
2024	*1.90*	*1.00*	*1.15*	*.85*	*4.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.59	.59	.59	.59	2.36
2020	.6325	.6325	.6325	.6325	2.53
2021	.6775	.6775	.6775	.6775	2.71
2022	.7275	.7275	.7275	.7275	2.91
2023	.7800	.7800			

BUSINESS: WEC Energy Group, Inc. (formerly Wisconsin Energy) is a holding company for utilities that provide electric, gas & steam service in WI & gas service in IL, MN, & MI. Customers: 1.6 mill. elec., 2.9 mill. gas. Acq'd Integrys Energy 6/15. Sold Point Beach nuclear plant in '07. Electric revenue breakdown: residential, 39%; small commercial & industrial, 32%; large commercial & industrial, 21%; other, 8%. Generating sources: coal, 36%; gas, 28%; renewables, 5%; purchased, 31%. Fuel costs: 40% of revenues. '22 reported deprec. rates: 2.4%-3.1%. Has 6,900 employees. Chairman: Gale E. Klappa. President & CEO: Scott J. Lauber. Inc.: WI. Address: 231 W. Michigan St., P.O. Box 1331, Milwaukee, WI 53201. Tel.: 414-221-2345. Internet: www.wecenergygroup.com.

WEC Energy's utility in Minnesota reached a settlement in its rate case. The settlement, if approved by the Minnesota Commission, will grant Minnesota Energy Resources a 7.1% increase in base rates, based on a 9.65% return on equity. In March, the company's utility in Michigan filed a base rate increase of 9.1% for 2024. The company also had pending rate cases in Illinois for Peoples Gas and North Shore Gas. Hearings are scheduled for August, and new tarrifs are expected to take effect by next year.

Our 2023 bottom-line projection is staying put at $4.60 per share, which is the midpoint of management's updated guidance range. The Energy Infrastructure segment's earnings dropped $0.01 a share and the corporate segment's earnings fell $0.08 a share compared to the first quarter of 2022. Too, natural gas deliveries in Wisconsin declined by 10.5% year over year due to one of the mildest winters in history. On a positive note, rate relief remains a main driver to performance, and contributed $0.22 a share to earnings in the March period. The bottom-line will likely continue to benefit from a number of pending gas rate hikes. The company expects profits in the second-half of 2023 to be materially better than last year. Our projections mirror this sentiment.

The company is making progress on a number of zero carbon projects. The Red Barn Wind purchase went to service in April, and is providing 82 megawatts of clean energy to Wisconsin customers. In February, WEC received approval for 100 megawatts of Riverside capacity for approximately $102 million, and also completed its acquisition of a Sapphire Farm, which currently offers 250 megawatts of capacity in total. There are many other capital projects that are underway, which will provide assistance to the company's zero carbon goals.

WEC Energy stock likely will appeal to conservative investors. The utility holds a strong Price Stability and Earnings Predictability scores, as well as a top notch Safety rank. Too, the dividend yield of 3.6% is right around the industry average. Total return potential to 2026-2028 is modest, however.

Zachary J. Hodgkinson *June 9, 2023*

(A) Diluted EPS. Excl. gain on discontinued ops.: '11, 6¢; nonrecurring gain: '17, 65¢. Next earnings report due early Aug. (B) Div'ds paid in early Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '22: $20.05/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in WI in '15: 10.0%-10.2%; in IL in '21: 9.67%; in MN in '19: 9.7%; in MI in '22: 9.85%; earned on avg. com. eq., '21: 12.2%. Regulatory Climate: WI, Above Average; IL, Below Average; MN & MI, Average.

Company's Financial Strength	A+
Stock's Price Stability	90
Price Growth Persistence	70
Earnings Predictability	100

XCEL ENERGY NDQ-XEL

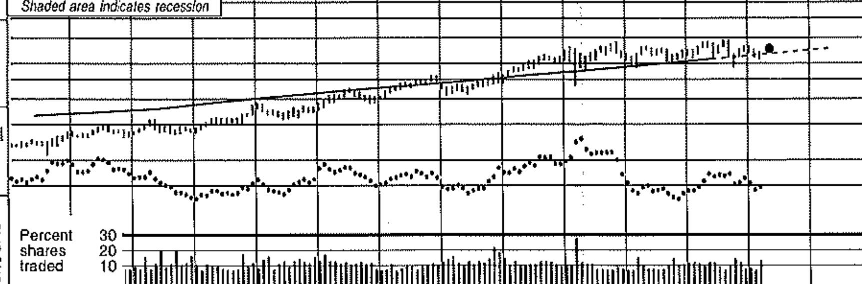
RECENT PRICE 70.76 | P/E RATIO 21.2 (Trailing: 22.3 / Median: 20.0) | RELATIVE P/E RATIO 1.23 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 4 Lowered 4/21/23
SAFETY 1 Raised 5/1/15
TECHNICAL 5 Lowered 3/31/23
BETA .80 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	29.9	31.8	37.6	38.3	45.4	52.2	54.1	66.1	76.4	72.9	77.7	73.0
Low:	25.8	26.8	27.3	31.8	35.2	40.0	41.5	47.7	46.6	57.2	56.9	62.8

Target Price Range 2026 | 2027 | 2028

LEGENDS
— 32.3 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$55-$95 $75 (5%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+35%)	10%
Low	75	(+5%)	5%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	453	436	485
to Sell	368	340	362
Hld's(000)	424573	424931	427005

Percent shares traded 30 20 10

% TOT. RETURN 3/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-3.8	-5.8
3 yr.	21.5	98.5
5 yr.	70.7	50.6

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
23.40	24.69	21.08	21.38	21.90	20.76	21.92	23.11	21.72	21.90	22.46	22.44	21.98	21.45	24.69	27.86	*27.80*	*28.55*	Revenues per sh	*30.35*
3.45	3.50	3.48	3.51	3.79	4.00	4.10	4.28	4.56	5.04	5.47	5.92	6.25	6.61	7.08	7.81	*8.25*	*8.65*	"Cash Flow" per sh	*10.00*
1.35	1.46	1.49	1.56	1.72	1.85	1.91	2.03	2.10	2.21	2.30	2.47	2.64	2.79	2.96	3.17	*3.35*	*3.55*	Earnings per sh A	*4.25*
.91	.94	.97	1.00	1.03	1.07	1.11	1.20	1.28	1.36	1.44	1.52	1.62	1.72	1.83	1.95	*2.08*	*2.22*	Div'd Decl'd per sh B ■ †	*2.66*
4.89	4.66	3.91	4.60	4.53	5.27	6.82	6.33	7.26	6.42	6.54	7.70	8.05	9.99	7.80	8.44	*9.00*	*9.25*	Cap'l Spending per sh	*9.50*
14.70	15.35	15.92	16.76	17.44	18.19	19.21	20.20	20.89	21.73	22.56	23.78	25.24	27.12	28.70	30.34	*31.60*	*33.15*	Book Value per sh C	*38.25*
428.78	453.79	457.51	482.33	486.49	487.96	497.97	505.73	507.54	507.22	507.76	514.04	524.54	537.44	544.03	549.58	*550.00*	*553.00*	Common Shs Outst'g D	*560.00*
16.7	13.7	12.7	14.1	14.2	14.8	15.0	15.4	16.5	18.5	20.2	18.9	22.3	23.9	22.5	22.2	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*20.0*
.89	.82	.85	.90	.89	.94	.84	.81	.83	.97	1.02	1.02	1.19	1.23	1.22	1.29	*estimates*		Relative P/E Ratio	*1.10*
4.0%	4.7%	5.1%	4.5%	4.2%	3.9%	3.9%	3.8%	3.7%	3.3%	3.1%	3.3%	2.7%	2.6%	2.8%	2.8%			Avg Ann'l Div'd Yield	*3.1%*

CAPITAL STRUCTURE as of 12/31/22
Total Debt $24777 mill. Due in 5 Yrs $3808 mill.
LT Debt $22813 mill. LT Interest $809 mill.
Incl. $228 mill. finance leases.
(Total Interest Coverage: 2.8x)

Leases, Uncapitalized Annual rentals $264 mill.
Pension Assets-12/21 $2685 mill. Oblig $2871 mill.

Pfd Stock None

Common Stock 549,847,034 shs.
as of 2/16/23
MARKET CAP: $38.9 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
10915	11686	11024	11107	11404	11537	11529	11526	13431	15310	*14350*	*15800*	Revenues ($mill)	*17000*
948.2	1021.3	1063.6	1123.4	1171.0	1261.0	1372.0	1473.0	1597.0	1736.0	*1725*	*1960*	Net Profit ($mill)	*2385*
33.8%	33.9%	35.8%	34.1%	30.7%	12.6%	8.5%	--	--	--	*NMF*	*NMF*	Income Tax Rate	*NMF*
13.4%	12.5%	7.7%	7.8%	9.4%	12.4%	8.3%	10.7%	6.2%	5.9%	*6.0%*	*6.0%*	AFUDC % to Net Profit	*6.0%*
53.3%	53.0%	54.1%	56.3%	55.9%	56.4%	56.8%	57.4%	58.2%	57.8%	*58.0%*	*58.0%*	Long-Term Debt Ratio	*58.0%*
46.7%	47.0%	45.9%	43.7%	44.1%	43.6%	43.2%	42.6%	41.8%	42.2%	*42.0%*	*42.0%*	Common Equity Ratio	*42.0%*
20477	21714	23092	25216	25975	28025	30646	34220	37391	39488	*41750*	*44075*	Total Capital ($mill)	*50900*
26122	28757	31206	32842	34329	36944	39483	42950	45457	48253	*50525*	*52850*	Net Plant ($mill)	*59700*
6.0%	6.0%	5.8%	5.7%	5.8%	5.7%	5.6%	5.4%	5.3%	5.5%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	10.1%	10.2%	10.4%	*10.5%*	*10.5%*	Return on Shr. Equity	*11.0%*
9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	10.1%	10.2%	10.4%	*10.5%*	*10.5%*	Return on Com Equity E	*11.0%*
4.5%	4.5%	4.3%	4.0%	3.9%	4.3%	4.4%	4.2%	4.2%	4.3%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
54%	55%	57%	61%	62%	58%	58%	58%	59%	58%	*62%*	*62%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-2.3	+1.4	+1.2
Resid'l Revs. per KWH (¢)	12.12	12.94	13.41
C & I Revs. per KWH (¢)	7.86	8.73	9.02
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	19665	19849	20346
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	252	262	255

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	1.5%	2.5%	*3.5%*
"Cash Flow"	6.5%	7.5%	*5.5%*
Earnings	5.5%	6.0%	*6.0%*
Dividends	6.0%	6.0%	*6.5%*
Book Value	5.0%	5.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	2811	2586	3182	2947	11526
2021	3541	3068	3467	3355	13431
2022	3751	3424	4082	4053	15310
2023	*3900*	*3550*	*4000*	*3850*	*15300*
2024	*4050*	*3675*	*4125*	*3950*	*15800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.56	.54	1.14	.54	2.79
2021	.67	.58	1.13	.58	2.96
2022	.70	.60	1.18	.69	3.17
2023	*.75*	*.65*	*1.25*	*.70*	*3.35*
2024	*.79*	*.69*	*1.33*	*.74*	*3.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.38	.405	.405	.405	1.60
2020	.405	.43	.43	.43	1.70
2021	.43	.4575	.4575	.4575	1.80
2022	.4575	.4875	.4875	.4875	1.92
2023	.4875	.52			

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power Company (NSP), which supplies electricity to MN, WI, ND, SD & MI & gas to MN, WI, ND & MI; Public Service Company of Colorado (PSCo), which supplies electricity & gas to CO; & Southwestern Public Service Company (SPS), which supplies electricity to TX and NM. Customers: 3.8 mill. electric, 2.1 mill. gas. Electric revenues: resid'l, 29%; comm'l & ind'l, 48%; other, 23%. Purchases 33% of power, owns 67. Total electric mix: wind, 33%; gas, 24%; coal, 23%, nuclear, 13%, solar/other, 7%. Fuel costs: 45% of revenues. '22 deprec. rate: 3.7%. Employs 11,982. President, CEO and Chrmn.: Robert Frenzel. Inc.: MN. Addr.: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Int.: www.xcelenergy.com.

A steady stream of general rate case (GRC) filings are likely to keep Xcel Energy's earnings on the rise in 2023 and 2024. Leadership has reaffirmed its bottom-line outlook of $3.30 to $3.40 per share for this year, which is consistent with the company's longer-term growth objective of 5%-7%. Xcel is the epitome of consistency within the electric utility industry, and has a solid track record of delivering on its year-ahead earnings pronouncements. Touching on some of the more notable pending GRCs, the company has Minnesota electric and gas cases on file with decisions due later this year. Electric revenue increases of $288 million for 2022 and $135 million for 2023 are being sought. A gas rate increase of $21 million for 2022 is also being requested. In November, Xcel filed an electric case in Colorado seeking a net increase of $262 million. A decision and implementation of final rates is expected in this year's third quarter. An electric GRC is also on file in New Mexico, with a $78 million rate increase sought starting from 2022's fourth quarter. Cases for Texas and Wisconsin are expected to be filed shortly.

Xcel has multiple renewable-energy projects in the works. The Colorado commission approved the company's resource plan, which includes about 4,000 megawatts (mw) of renewable additions and the conversion of a major plant from coal to natural gas. This is in addition to the approved Minnesota plan, which adds 6,000 mw of renewables. Request for proposals have been filed and commission decisions on the finer details are expected in the second half of this year. In the electric-vehicle (EV) arena, Xcel is working towards its goal of powering 1.5 million EVs by 2030. These sorts of projects are expected to keep the company's rate base growing at a 7% clip for many years to come. Through the regulatory process, paired with excellent execution, that should translate to a commensurate level of annual profit growth.

This issue is untimely. Still, we like XEL as a long-term core holding for utility investors, but advise waiting for a better entry point. Risk-adjusted total return potential would be worthwhile following a 5%-10% drawdown in the share price.

Anthony J. Glennon *April 21, 2023*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '10, 5¢; '15, (16¢); '17, (5¢); gains (loss) on discontinued ops.: '09, (1¢); '10, 1¢. '20 EPS don't sum due to rounding. Next earnings report due April 27th.
(B) Div'ds historically paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan available. † Shareholder investment plan available.
(C) Incl. intangibles. In '22: $2871 mill., $5.22/sh. (D) In mill. (E) Rate base: Varies. Rate allowed on common equity (blended): 9.6%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	100

CASE: UE 416
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 2902

ROE – Three-Stage DCF: Peer Screen, Dividends, Earnings per Share (EPS), and Hamada Equation

August 22, 2023

Acronyms and Abbreviations Used

BOE U.S. Bureau of Economic Analysis
CBO U.S. Congressional Budget Office
CIK SEC Central Index Key
EDGAR SEC Electronic Data Gathering, Analysis and Retrieval System
EEI Edison Electric Institute
EIN IRS Employer Identification Number
IRS U.S. Internal Revenue Service
SEC U.S. Securities and Exchange Commission
SIC Standard Industrial Code
SPG Standard & Poors Global Market Intelligence
TIPS UST Treasury Inflation-Protected Securities
U.S. United States of America
UST U.S. Treasuries
VL Value Line Investment Survey

Moody's		S&P		Fitch		DBRS		
Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	
Aaa	P-1	AAA	A-1+	AAA	F1+	AAA	R-1H	High Grade
Aa1		AA+		AA+		AA(high)		High grade
Aa2		AA		AA		AA	R-1M	
Aa3		AA-		AA-		AA(low)		
A1		A+	A-1	A+	F1	A(high)	R-1L	Upper medium grade
A2		A		A		A		
A3	P-2	A-	A-2	A-	F2	A(low)		
Baa1		BBB+		BBB+		BBB(high)	R-2H	Lower medium grade
Baa2	P-3	BBB	A-3	BBB	F3	BBB	R-2M	
Baa3		BBB-		BBB-		BBB(low)	R-2L, R-3	
Ba1	Not prime	BB+	B	BB+	B	BB(high)	R-4	Non-investment grade speculative
Ba2		BB		BB		BB		
Ba3		BB-		BB-		BB(low)		
B1		B+		B+		B(high)		Highly speculative
B2		B		B		B	R-5	
B3		B-		B-		B(low)		
Caa1		CCC+				CCC(high)		Substantial risks
Caa2		CCC				CCC		
Caa3		CCC-				CCC(low)		
						CC(high)		
		CC	C	CCC	C	CC		

Source: http://en.wikipedia.org/wiki/Credit_rating

S	Small Cap	Under 2 Billion
M	Mid Cap	2 to 10 Billion
L	Large Cap	Over 10 Billion

1 PGE Peer Group
2 Staff Peer Group

1 VL #	2 Abbreviated Utility	3 UE 416 PGE	4 UE 416 Staff	5 VL Corporate Name Electric Utility	6 SEC Edgar CIK	7 SEC Edgar SIC	8 SEC File #	9 IRS EIN #	10 Ticker	11 VL Region	12 LT Debt Sensitivity UE 416 Staff	13 VL 7/5/2023 Beta	14 VL $B 7/5/2023 Mkt Cap $ Billions	15 VL 7/5/2023 S,M,L CAP	16 Yahoo Fin. 7/3/2023 Beta	17 Yahoo Fin. 7/3/2023 Mkt Cap $ Billions	18 Covered by Value Line 7/20/2023 (VL)	19 VL 7/6/2023 No Div Declines 5 years	20 Moody's 7/7/2023 A1 to Baa2 Local LT Unsecured Debt Rating	21 S&P 7/7/2023 A to BBB- Local LT Rating
1	Allete	Yes	No	Allete, Inc.	0000066756	4931	1-3548	41-0418150	ALE	Central	No	0.90	3.50	M	0.74	3.33	Yes	Pass	Baa1	BBB
2	Alliant	Yes	Yes	Alliant Energy Corporation	0000352541	4931	1-9894	39-1380265	LNT	Central	Yes	0.85	12.80	L	0.54	13.33	Yes	Pass	Baa2	A-
3	Ameren	Yes	Yes	Ameren Corporation	0001002910	4931	1-14756	43-1723446	AEE	Central	Yes	0.85	21.20	L	0.45	21.82	Yes	Pass	Baa1	BBB+
4	AEP	Yes	No	American Electric Power Company, Inc.	0000004904	4911	1-3525	13-4922640	AEP	Central	Yes	0.75	42.30	L	0.46	43.99	Yes	Pass	Baa2	A-
5	Avangrid	No	No	Avangrid, Inc. (ex merger: *Iberdrola USA & UIL*)	0001634997	4911	1-37660	14-1798693	AGR	East	No	0.85	15.70	L	0.44	14.78	Yes	Pass	Baa2	BBB+
6	Avista	Yes	Yes	Avista Corporation	0000104918	4931	1-3701	91-0462470	AVA	West	Yes	0.90	3.30	M	0.51	2.96	Yes	Pass	Baa2	BBB
7	Black Hills	Yes	No	Black Hills Corporation	0001130464	4911	1-31303	46-0458824	BKH	West	Yes	0.95	4.40	M	0.58	4.05	Yes	Pass	Baa2	BBB+
8	CenterPoint	Yes	No	CenterPoint Energy, Inc.	0001130310	4911	1-31447	74-0694415	CNP	Central	No	1.10	17.90	L	0.89	18.72	Yes	Fail	Baa2	BBB+
9	CMS	Yes	No	CMS Energy Corporation	0000811156	4931	1-9513	38-2726431	CMS	Central	No	0.80	16.70	L	0.36	17.57	Yes	Pass	Baa2	BBB+
10	Consol Ed	No	Yes	Consolidated Edison, Inc.	0001047862	4931	1-14514	13-3965100	ED	East	Yes	0.75	35.20	L	0.37	31.93	Yes	Pass	Baa2	A-
11	Dominion	Yes	No	Dominion Energy, Inc.	0000715957	4911	1-08489	54-1229715	D	East	No	0.85	47.70	L	0.46	44.52	Yes	Pass	Baa2	BBB+
12	DTE	No	No	DTE Energy Company	0000936340	4911	1-11607	38-3217752	DTE	Central	No	0.95	21.90	L	0.60	23.20	Yes	Fail	Baa2	BBB+
13	Duke	Yes	No	Duke Energy Corporation	0001326160	4931	1-32853	20-2777218	DUK	East	Yes	0.85	76.20	L	0.43	70.97	Yes	Pass	Baa2	BBB+
14	Edison Int'l	Yes	No	Edison International	0000827052	4911	1-9936	95-4137452	EIX	West	No	0.95	27.90	L	0.83	26.82	Yes	Pass	Baa2	BBB
15	Entergy	Yes	No	Entergy Corporation	0000065984	4911	1-11299	72-1229752	ETR	Central	No	0.90	20.50	L	0.65	21.04	Yes	Pass	Baa2	BBB+
16	Evergy	Yes	Yes	Evergy, Inc. (Holds Great Plains & Westar)	0001711269	4931	1-38515	82-2733395	EVRG	Central	Yes	0.90	13.20	L	0.50	13.73	Yes	Pass	Baa2	A-
17	Eversource	No	Yes	Eversource Energy (formerly: *Northeast Utilities*)	0000072741	4911	1-5324	04-2147929	ES	East	Yes	0.90	27.10	L	0.49	25.27	Yes	Pass	Baa1	A-
18	Exelon	Yes	No	Exelon Corporation	0001109357	4931	1-16169	23-2990190	EXC	East	No	0.00	42.90	L	0.61	41.30	Yes	Fail	Baa2	BBB+
19	First Energy	No	No	FirstEnergy Corporation (Formerly in part: Allegheny)	0001031296	4911	333-21011	34-1843785	FE	East	No	0.85	22.30	L	0.44	22.79	Yes	Fail	Ba1	BBB-
20	Fortis	No	No	Fortis, Inc.	001666175	4911	1-37915	98-0352146	FTS	Central	No	0.70	27.80	L	0.20	20.92	Yes	Pass	Baa3	A-
21	Hawaiian	No	No	Hawaiian Electric Industries, Inc.	0000354707	4911	1-8503	99-0208097	HE	West	No	0.85	4.30	M	0.41	4.03	Yes	Pass	Withdrawn	BBB-
22	IDACORP	Yes	Yes	IDACORP, Inc.	0001057877	4911	1-14465	82-0505802	IDA	West	Yes	0.80	5.60	M	0.62	5.29	Yes	Pass	Baa2	BBB
23	MGE	Yes	No	MGE Energy, Inc. (Madison Gas & Electric Co.)	0001161728	4900	0-49965	39-2040501	MGEE	Central	No	N/A	N/A	M	0.72	2.90	No	Fail	A1	AA-
24	NextEra	Yes	No	NextEra Energy, Inc. (Formerly: FPL Group, Inc.)	0000753308	4911	1-8841	59-2449419	NEE	East	No	0.95	155.40	L	0.47	151.81	Yes	Pass	Baa1	A-
25	NorthWestern	Yes	Yes	NorthWestern Corporation	0000073088	4931	1-10499	46-0172280	NWE	West	Yes	0.90	3.60	M	0.46	3.45	Yes	Pass	Baa2	BBB
26	OGE	Yes	Yes	OGE Energy Corporation	0001021635	4911	1-12579	73-1481638	OGE	Central	Yes	1.00	7.00	M	0.70	7.35	Yes	Pass	Baa1	BBB+
27	Otter Tail	Yes	No	Otter Tail Corporation	0001466593	4911	0-53713	27-0383995	OTTR	Central	Yes	0.85	3.10	M	0.51	3.31	Yes	Pass	A3	BBB
28	PG&E	No	No	PG&E Corporation	0001004980	4931	1-12609	94-3234914	PCG	West	No	N/A	N/A	L	1.14	41.99	No	Fail	Ba2	BB-
29	PGE	No	No	Portland General Electric Company	0000784977	4911	1-5532-99	93-0256820	POR	West	No	0.85	4.50	M	0.60	4.60	Yes	Pass	A3	BBB+
30	Pinnacle	Yes	Yes	Pinnacle West Capital Corporation	0000764622	4911	1-8962	86-0512431	PNW	West	Yes	0.90	9.10	M	0.45	9.38	Yes	Pass	Baa1	BBB+
31	PNM	No	No	PNM Resources, Inc.	0001108426	4911	1-32462	85-0468296	PNM	West	No	0.90	4.20	M	0.42	3.92	Yes	Pass	Baa3	BBB
32	PPL	No	No	PPL Corporation	0000922224	4911	1-11459	23-2758192	PPL	East	No	1.05	21.20	L	0.80	19.85	Yes	Fail	Baa1	A-
33	Public Serv.	Yes	No	Public Serv. Enterprise Group, Inc.	0000788784	4931	1-09120	22-2625848	PEG	East	No	0.90	31.50	L	0.58	31.92	Yes	Pass	Baa2	BBB+
34	Sempra	Yes	Yes	Sempra Energy	0001032208	4932	1-14201	33-0732627	SRE	West	Yes	0.95	48.80	L	0.74	46.27	Yes	Pass	Baa2	BBB+
35	Southern	Yes	No	Southern Company (Southern Company Gas)	0000092122	4911	1-3526	58-0690070	SO	East	No	0.90	80.80	L	0.51	78.16	Yes	Pass	Baa2	BBB+
36	WEC	Yes	Yes	WEC Energy Group (formerly Wisconsin Energy)	0000783325	4931	1-09057	39-1391525	WEC	Central	Yes	0.80	27.40	L	0.41	28.58	Yes	Pass	Baa1	A-
37	Xcel	Yes	No	Xcel Energy, Inc.	0000072903	4931	1-3034	41-0448030	XEL	West	Yes	0.80	38.90	L	0.44	34.99	Yes	Pass	Baa1	A-
	No. of Peers:	26	12							AVG:	17	0.86								

	Moody's	S&P
PGE	A3	A
Range	A1 to Baa2	A to BBB-

S	Small Cap	Under 2 Billion	
M	Mid Cap	2 to 10 Billion	
L	Large Cap	Over 10 Billion	

1	2	3	4	22	23	24	25	26	27	28	
								Sensitivity			
				+ / -	SEC 10-K	EEI	VL	VL	VL		
				2	2/10/2023	7/7/2023	7/6/2023	7/6/2023	2/2/2023	No	
				Notches	Percentage	80%+	LT Debt	LT Debt	Div. Growth	M&A Executed	
VL #	Abbreviated Utility	UE 416 PGE	UE 416 Staff	S&P & Moody's	Regulated Revenue	Regulated Assets	45% - 55% of Capital	40% - 60% of Capital	5 Yr Rate Forecast > 0%	in Last 5 Years	#
1	Allete	Yes	No	Pass	80%	50% to 80%	39.5%	39.5%	Yes		1
2	Alliant	Yes	Yes	Pass	97%	80% +	52.5%	52.5%	Yes		2
3	Ameren	Yes	Yes	Pass	100%	80% +	53.5%	53.5%	Yes		3
4	AEP	Yes	No	Pass	83%	80% +	58.0%	58.0%	Yes	Sale of KY Power Subsidiary for $1.45 Billion expected to be completed in 2022 Q2	4
5	Avangrid	No	No	Pass	N/A	50% to 80%	32.0%	32.0%	Fail	Proposes to by PNM for $4.3 Billion, Has financed acquisition / VL. Companies appealed to the state Supreme Court.	5
6	Avista	Yes	Yes	Pass	99%	80% +	50.5%	50.5%	Yes	H1 Failed to Buy Avista 2019	6
7	Black Hills	Yes	No	Pass	100%	80% +	55.5%	55.5%	Yes		7
8	CenterPoint	Yes	No	Pass	80%	80% +	55.0%	55.0%	Fail	CenterPoint Acquired Vectren Feb 2019 $6 B Deal, Sold 2 Gas Utilities in AR and OK 2022 Now Exiting position in Enable Mistream Partners	8
9	CMS	Yes	No	Pass	94%	80% +	62.5%	62.5%	Yes		9
10	Consol Ed	No	Yes	Pass	84%	80% +	48.0%	48.0%	Yes		10
11	Dominion	Yes	No	Pass	95%	80% +	58.0%	58.0%	Fail	2019 Purchase of Scana, 2020 Sale gas pipeline / storage $9.7B to Berkshire Energy	11
12	DTE	No	No	Pass	52%	80% +	61.5%	61.5%	Fail	2021 Spun Off subsidiary into DT Midstream NYSE:DTM	12
13	Duke	Yes	No	Pass	100%	80% +	58.5%	58.5%	Yes	12/27/22 GIC Pte. Ltd purchased minor stake in Duke Energy Indiana LLC all-cash valued at $2.05B for a total interest to 19.9%.	13
14	Edison Int'l	Yes	No	Pass	100%	80% +	61.0%	61.0%	Yes	Aug **2000** Bought Citizens Power, Nuclear Gen w San Onofre Nuclear Generation Station (SONGS)	14
15	Entergy	Yes	No	Pass	98%	80% +	64.5%	64.5%	Yes		15
16	Evergy	Yes	Yes	Pass	100%	80% +	51.5%	51.5%	Yes		16
17	Eversource	No	Yes	Pass	100%	80% +	56.5%	56.5%	Yes		17
18	Exelon	Yes	No	Pass	67%	80% +	61.0%	61.0%	Fail	Exelon completed Spin Off of Nonutility Opertions on Feb. 1, 2022	18
19	First Energy	No	No	Fail	100%	80% +	66.0%	66.0%	Fail		19
20	Fortis	No	No	Fail	55%	N/A	53.0%	53.0%	Yes		20
21	Hawaiian	No	No	Pass	77%	50% to 80%	51.0%	51.0%	Yes	Failed Attempt by Next Era to Buy HECO for $17B in 2017	21
22	IDACORP	Yes	Yes	Pass	99%	80% +	47.0%	47.0%	Yes		22
23	MGE	Yes	No	Fail	99%	80% +	N/A	N/A	Yes		23
24	NextEra	Yes	No	Pass	70%	50% to 80%	59.0%	59.0%	Yes	Next Era Failed to Buy HECO for $17B in 2017, Next Era Failed to Buy Oncor for $17B in 2017	24
25	NorthWestern	Yes	Yes	Pass	99%	80% +	46.5%	46.5%	Yes		25
26	OGE	Yes	Yes	Pass	100%	80% +	52.0%	52.0%	Yes		26
27	Otter Tail	Yes	No	Pass	80%	80% +	41.5%	41.5%	Yes		27
28	PG&E	No	No	Fail	N/A	80% +	N/A	N/A	Fail	2019 Chapter 11 bankruptcy liability for 2017 and 2018 wildfires in CA	28
29	PGE	No	No	Pass	100%	80% +	54.5%	54.5%	Yes		29
30	Pinnacle	Yes	Yes	Pass	100%	80% +	52.5%	52.5%	Yes		30
31	PNM	No	No	Fail	100%	80% +	62.5%	62.5%	Yes	Avangrid Proposal to Purchase PNM, now more viable with newly constituted NW PRC	31
32	PPL	No	No	Pass	100%	80% +	46.5%	46.5%	Fail	2021 Sold operations in UK, Buying Narragansett Electric for $3.8B	32
33	Public Serv.	Yes	No	Pass	64%	80% +	53.5%	53.5%	Yes		33
34	Sempra	Yes	Yes	Pass	80%	80% +	50.5%	50.5%	Yes	Bought Oncor March 2018 for $9.5 B	34
35	Southern	Yes	No	Pass	96%	80% +	64.0%	64.0%	Yes	2016 AGL Resources merged with Southern Company	35
36	WEC	Yes	Yes	Pass	100%	80% +	55.0%	55.0%	Yes		36
37	Xcel	Yes	No	Pass	100%	80% +	58.0%	58.0%	Yes		37
	No. of Peers:	26	12								

Edision Electric Instutute (EEI)

Assets	EEI	Meaning
80% Plus	R	Regulated
50% to 80%	MR	Mostly Regulated
Under 50%	D	Diversified

EEI Updates each June to end of prior year.

Value Line
Historical and Near Term
Dividends Declared per Share
(Div)

	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		
					Staff Sensitivity																						Value Line Estimated Dividends						VL	VL % Div Growth		
	Screen #	Abbreviated Utility	UE 416 PGE	UE 416 Staff	UE 416 LT Debt	2018 Q1	2018 Q2	2018 Q3	2018 Q4	2018 Yr	2019 Q1	2019 Q2	2019 Q3	2019 Q4	2019 Yr	2020 Q1	2020 Q2	2020 Q3	2020 Q4	2020 Yr	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2021 Yr	2019-21 Average	2022 Yr	2023 Yr	2024 Yr	2025 Yr	2026 Yr	2027 Yr	2026 - 28 Average	2025 - 27 vs. 2019 - 21	Screen #	
1	1	Allete	Yes	No	No	0.560	0.560	0.560	0.560	**2.24**	0.5875	0.5875	0.5875	0.5875	**2.35**	0.6175	0.6175	0.6175	0.6175	**2.47**	0.630	0.630	0.630	0.630	**2.52**	**2.45**	**2.60**	**2.71**	**2.80**	**2.90**	**3.00**	**3.10**	**3.00**	**3.5%**	1	1
2	2	Alliant	Yes	**Yes**	**Yes**	0.335	0.335	0.335	0.335	**1.34**	0.355	0.355	0.355	0.355	**1.42**	0.380	0.380	0.380	0.380	**1.52**	0.4025	0.4025	0.4025	0.4025	**1.61**	**1.52**	**1.71**	**1.81**	**1.96**	**2.12**	**2.29**	**2.46**	**2.29**	**7.1%**	2	2
3	3	Ameren	Yes	**Yes**	**Yes**	0.4575	0.4575	0.4575	0.475	**1.85**	0.475	0.475	0.475	0.495	**1.92**	0.4950	0.4950	0.4950	0.515	**2.00**	0.550	0.550	0.550	0.550	**2.20**	**2.04**	**2.36**	**2.52**	**2.76**	**3.02**	**3.30**	**3.58**	**3.30**	**8.3%**	3	3
4	4	AEP	Yes	No	**Yes**	0.620	0.620	0.620	0.670	**2.53**	0.670	0.670	0.670	0.700	**2.71**	0.700	0.700	0.700	0.740	**2.84**	0.740	0.740	0.740	0.780	**3.00**	**2.85**	**3.17**	**3.35**	**3.60**	**3.87**	**4.16**	**4.45**	**4.16**	**6.5%**	4	4
5	6	Avista	Yes	**Yes**	**Yes**	0.3725	0.3725	0.3725	0.3725	**1.49**	0.3875	0.3875	0.3875	0.3875	**1.55**	0.405	0.405	0.405	0.405	**1.62**	0.4225	0.4225	0.4225	0.4225	**1.69**	**1.62**	**1.76**	**1.84**	**1.94**	**2.04**	**2.15**	**2.26**	**2.15**	**4.8%**	6	5
6	7	Black Hills	Yes	No	**Yes**	0.475	0.475	0.475	0.505	**1.93**	0.505	0.505	0.505	0.535	**2.05**	0.535	0.535	0.535	0.5650	**2.17**	0.565	0.565	0.565	0.596	**2.29**	**2.17**	**2.41**	**2.53**	**2.70**	**2.88**	**3.07**	**3.26**	**3.07**	**6.0%**	7	6
7	8	CenterPoint	Yes	No	No	0.2775	0.2775	0.2775	0.2775	**1.11**	0.2875	0.2875	0.2875	0.2875	**1.15**	0.29	0.15	0.15	0.15	**0.74**	0.16	0.16	0.16	0.17	**0.65**	**0.85**	**0.72**	**0.77**	**0.83**	**0.89**	**0.95**	**1.01**	**0.95**	**1.9%**	8	7
8	9	CMS	Yes	No	No	0.358	0.358	0.358	0.358	**1.43**	0.383	0.383	0.383	0.383	**1.53**	0.408	0.408	0.408	0.408	**1.63**	0.44	0.44	0.44	0.44	**1.74**	**1.63**	**1.84**	**1.95**	**2.06**	**2.18**	**2.30**	**2.42**	**2.30**	**5.9%**	9	8
9	10	Consol Ed	No	**Yes**	**Yes**	0.7150	0.7150	0.7150	0.7150	**2.86**	0.740	0.740	0.740	0.740	**2.96**	0.7650	0.7650	0.7650	0.7650	**3.06**	0.7750	0.7750	0.7750	0.7750	**3.1**	**3.04**	**3.16**	**3.24**	**3.43**	**3.64**	**3.86**	**4.08**	**3.86**	**4.1%**	10	9
10	11	Dominion	Yes	No	No	0.835	0.835	0.835	0.835	**3.34**	0.9175	0.9175	0.9175	0.9175	**3.67**	0.94	0.94	0.94	0.63	**3.45**	0.63	0.63	0.63	0.630	**2.52**	**3.21**	**2.67**	**2.67**	**2.82**	**2.99**	**3.16**	**3.33**	**3.16**	**-0.3%**	11	10
11	13	Duke	Yes	No	**Yes**	0.890	0.890	0.928	0.928	**3.64**	0.928	0.928	0.945	0.945	**3.75**	0.945	0.945	0.965	0.965	**3.82**	0.965	0.965	0.985	0.985	**3.90**	**3.82**	**3.98**	**4.06**	**4.14**	**4.22**	**4.30**	**4.38**	**4.30**	**2.0%**	13	11
12	14	Edison Int'l	Yes	No	No	0.605	0.605	0.605	0.605	**2.42**	0.6125	0.6125	0.6125	0.6125	**2.45**	0.6375	0.6375	0.6375	0.6375	**2.55**	0.6625	0.6625	0.6625	0.6625	**2.65**	**2.55**	**2.84**	**2.95**	**3.17**	**3.40**	**3.65**	**3.90**	**3.65**	**6.2%**	14	12
13	15	Entergy	Yes	No	No	0.8900	0.8900	0.8900	0.9100	**3.58**	0.9100	0.9100	0.9100	0.9300	**3.66**	0.930	0.930	0.930	0.950	**3.74**	0.950	0.950	0.950	1.010	**3.86**	**3.75**	**4.10**	**4.30**	**4.52**	**4.75**	**5.00**	**5.25**	**5.00**	**4.9%**	15	13
14	16	Evergy	Yes	**Yes**	**Yes**	0.400	0.400	0.460	0.475	**1.74**	0.475	0.475	0.475	0.505	**1.93**	0.505	0.505	0.505	0.535	**2.05**	0.535	0.535	0.535	0.5725	**2.18**	**2.05**	**2.33**	**2.53**	**2.69**	**2.87**	**3.05**	**3.23**	**3.05**	**6.8%**	16	14
15	17	Eversource	No	**Yes**	**Yes**	0.505	0.505	0.505	0.505	**2.02**	0.535	0.535	0.535	0.535	**2.14**	0.568	0.568	0.568	0.568	**2.27**	0.603	0.603	0.603	0.603	**2.41**	**2.27**	**2.55**	**2.70**	**2.94**	**3.20**	**3.48**	**3.76**	**3.48**	**7.4%**	17	15
16	18	Exelon	Yes	No	No	0.345	0.345	0.345	0.345	**1.38**	0.3625	0.3625	0.3625	0.3625	**1.45**	0.3825	0.3825	0.3825	0.3825	**1.53**	0.3825	0.3825	0.3825	0.3825	**1.53**	**1.50**	**1.35**	**1.44**	**1.55**	**1.67**	**1.80**	**1.93**	**1.80**	**3.0%**	18	16
17	22	IDACORP	Yes	**Yes**	**Yes**	0.590	0.590	0.590	0.6300	**2.40**	0.630	0.630	0.630	0.670	**2.56**	0.670	0.670	0.670	0.710	**2.72**	0.710	0.710	0.710	0.750	**2.88**	**2.72**	**3.04**	**3.20**	**3.49**	**3.81**	**4.15**	**4.49**	**4.15**	**7.3%**	22	17
18	23	MGE	Yes	No	No	0.3225	0.3225	0.3225	0.3375	**1.31**	0.3375	0.3375	0.3525	0.3525	**1.38**	0.3525	0.3525	0.370	0.370	**1.45**	0.370	0.370	0.3875	0.3875	**1.52**	**1.45**	**1.59**	**1.66**	**1.74**	**1.82**	**1.90**	**1.98**	**1.90**	**4.6%**	23	18
19	24	NextEra	Yes	No	No	0.2775	0.2775	0.2775	0.2775	**1.11**	0.313	0.313	0.313	0.313	**1.25**	0.3500	0.3500	0.3500	0.3500	**1.40**	0.3850	0.3850	0.3850	0.3850	**1.54**	**1.40**	**1.70**	**1.87**	**2.12**	**2.41**	**2.74**	**3.07**	**2.74**	**11.9%**	24	19
20	25	NorthWestern	Yes	**Yes**	**Yes**	0.550	0.550	0.550	0.550	**2.20**	0.575	0.575	0.575	0.575	**2.30**	0.600	0.600	0.600	0.600	**2.40**	0.620	0.6200	0.6200	0.6200	**2.48**	**2.39**	**2.52**	**2.56**	**2.63**	**2.69**	**2.76**	**2.83**	**2.76**	**2.4%**	25	20
21	26	OGE	Yes	**Yes**	**Yes**	0.3325	0.3325	0.3325	0.365	**1.36**	0.365	0.365	0.365	0.388	**1.48**	0.3875	0.3875	0.3875	0.4025	**1.57**	0.4025	0.4025	0.4025	0.41	**1.62**	**1.56**	**1.64**	**1.66**	**1.72**	**1.78**	**1.85**	**1.92**	**1.85**	**2.9%**	26	21
22	27	Otter Tail	Yes	No	**Yes**	0.335	0.335	0.335	0.3350	**1.34**	0.350	0.350	0.350	0.350	**1.40**	0.370	0.370	0.370	0.370	**1.48**	0.390	0.390	0.390	0.390	**1.56**	**1.48**	**1.65**	**1.76**	**1.90**	**2.04**	**2.20**	**2.36**	**2.20**	**6.8%**	27	22
23	30	Pinnacle	Yes	**Yes**	**Yes**	0.695	0.695	0.695	0.737	**2.82**	0.737	0.738	0.738	0.782	**3.00**	0.783	0.783	0.783	0.830	**3.18**	0.83	0.83	0.83	0.85	**3.34**	**3.17**	**3.42**	**3.48**	**3.57**	**3.66**	**3.75**	**3.84**	**3.75**	**2.8%**	30	23
24	33	Public Serv.	Yes	No	No	0.45	0.45	0.45	0.45	**1.80**	0.47	0.47	0.47	0.47	**1.88**	0.49	0.49	0.49	0.49	**1.96**	0.51	0.51	0.51	0.51	**2.04**	**1.96**	**2.16**	**2.28**	**2.44**	**2.61**	**2.80**	**2.99**	**2.80**	**6.1%**	33	24
25	34	Sempra	Yes	**Yes**	**Yes**	0.8225	0.895	0.895	0.895	**3.51**	0.8950	0.9675	0.9675	0.9675	**3.80**	0.968	1.045	1.045	1.045	**4.10**	1.045	1.10	1.10	1.10	**4.35**	**4.08**	**4.58**	**4.76**	**5.17**	**5.62**	**6.10**	**6.58**	**6.10**	**6.9%**	34	25
26	35	Southern	Yes	No	No	0.580	0.600	0.600	0.600	**2.38**	0.600	0.620	0.620	0.620	**2.46**	0.620	0.640	0.640	0.640	**2.54**	0.64	0.66	0.66	0.66	**2.62**	**2.54**	**2.70**	**2.78**	**2.88**	**2.99**	**3.10**	**3.21**	**3.10**	**3.4%**	35	26
27	36	WEC	Yes	**Yes**	**Yes**	0.5525	0.5525	0.5525	0.5525	**2.21**	0.590	0.590	0.590	0.590	**2.36**	0.6325	0.6325	0.6325	0.6325	**2.53**	0.6775	0.6775	0.6775	0.6775	**2.71**	**2.53**	**2.91**	**3.12**	**3.33**	**3.56**	**3.80**	**4.04**	**3.80**	**7.0%**	36	27
28	37	Xcel	Yes	No	**Yes**	0.360	0.380	0.380	0.380	**1.50**	0.380	0.405	0.405	0.405	**1.60**	0.405	0.430	0.430	0.430	**1.70**	0.430	0.4575	0.4575	0.4575	**1.80**	**1.70**	**1.95**	**2.08**	**2.26**	**2.45**	**2.66**	**2.87**	**2.66**	**7.8%**	37	28
		No. of Peers:	**26**	**12**	**17**																															

Note: MGE Was Not Covered by VL as of Mar 1, 2023, VL Data Shown is from March 11, 2022 VL Sheet

	Mean
Company Screen	**5.3%**
Staff Screen	**5.7%**
Staff LT Screen	**5.7%**

Value Line
Historical and Near Term
Earnings Per Share
(EPS)

Value Line Estimated EPS

	1 Screen #	2 Abbreviated Utility	3 UE 416 PGE	4 UE 416 Staff	5 Staff Sensitivity UE 416 LT Debt	6 2019 Q1	7 2019 Q2	8 2019 Q3	9 2019 Q4	10 2019 Yr	11 2020 Q1	12 2020 Q2	13 2020 Q3	14 2020 Q4	15 2020 Yr	16 2021 Q1	17 2021 Q2	18 2021 Q3	19 2021 Q4	20 2021 Yr	21 2019-21 Average
1	1	Allete	Yes	No	No	1.18	0.64	0.60	0.92	3.34	1.28	0.39	0.78	0.90	3.35	0.99	0.53	0.53	1.18	3.23	3.31
2	2	Alliant	Yes	Yes	Yes	0.53	0.40	0.94	0.46	2.33	0.72	0.54	0.94	0.26	2.46	0.68	0.57	1.02	0.35	2.62	2.47
3	3	Ameren	Yes	Yes	Yes	0.78	0.72	1.47	0.38	3.35	0.59	0.98	1.47	0.46	3.50	0.91	0.80	1.65	0.48	3.84	3.56
4	4	AEP	Yes	No	Yes	1.16	0.93	1.48	0.51	4.08	1.00	1.05	1.50	0.87	4.42	1.15	1.15	1.59	1.07	4.96	4.49
5	6	Avista	Yes	Yes	Yes	1.76	0.38	0.08	0.76	2.98	0.72	0.26	0.07	0.85	1.90	0.98	0.20	0.20	0.71	2.09	2.32
6	7	Black Hills	Yes	No	Yes	1.73	0.24	0.44	1.13	3.54	1.59	0.33	0.58	1.23	3.73	1.54	0.40	0.70	1.11	3.75	3.67
7	8	CenterPoint	Yes	No	No	0.28	0.33	0.47	0.41	1.49	0.56	0.17	0.29	0.27	1.29	0.41	0.29	0.21	0.03	0.94	1.24
8	9	CMS	Yes	No	No	0.75	0.33	0.73	0.58	2.39	0.85	0.48	0.76	0.55	2.64	1.09	0.55	0.54	0.40	2.58	2.54
9	10	Consol Ed	No	Yes	Yes	1.39	0.58	1.54	0.86	4.37	1.35	0.60	1.48	0.74	4.17	1.44	0.53	1.41	1.00	4.38	4.31
10	11	Dominion	Yes	No	No	1.10	0.77	1.18	1.18	4.23	0.92	0.73	1.08	0.81	3.54	1.09	0.76	1.11	0.90	3.86	3.88
11	13	Duke	Yes	No	Yes	1.24	1.12	1.79	0.91	5.06	1.14	1.08	1.87	1.03	5.12	1.26	1.15	1.88	0.94	5.23	5.14
12	14	Edison Int'l	Yes	No	No	0.64	1.57	1.35	0.45	4.01	0.50	0.85	-0.76	1.13	1.72	0.68	0.84	-0.90	1.38	2.00	2.58
13	15	Entergy	Yes	No	No	1.32	1.22	1.82	1.94	6.30	0.59	1.79	2.59	1.93	6.90	1.66	1.30	2.63	1.28	6.87	6.69
14	16	Evergy	Yes	Yes	Yes	0.39	0.57	1.56	0.28	2.80	0.31	0.59	1.60	0.22	2.72	0.84	0.81	1.95	0.23	3.83	3.12
15	17	Eversource	No	Yes	Yes	0.97	0.74	0.98	0.76	3.45	1.02	0.76	1.01	0.85	3.64	1.15	0.79	1.02	0.91	3.87	3.65
16	18	Exelon	Yes	No	No	0.87	0.60	0.92	0.83	3.22	0.87	0.55	1.04	0.76	3.22	-0.06	0.89	1.09	0.90	2.82	3.09
17	22	IDACORP	Yes	Yes	Yes	0.84	1.05	1.78	0.93	4.60	0.74	1.19	2.02	0.74	4.69	0.89	1.38	1.93	0.65	4.85	4.71
18	23	MGE	Yes	No	No	0.69	0.45	0.88	0.48	2.50	0.75	0.53	0.88	0.44	2.60	0.97	0.63	0.97	0.36	2.93	2.68
19	24	NextEra	Yes	No	No	0.35	0.64	0.45	0.50	1.94	0.59	0.65	0.67	0.40	2.31	0.67	0.71	0.75	0.41	2.54	2.26
20	25	NorthWesten	Yes	Yes	Yes	1.44	0.49	0.42	1.18	3.53	1.00	0.43	0.58	1.21	3.22	1.24	0.59	0.70	0.97	3.50	3.42
21	26	OGE	Yes	Yes	Yes	0.24	0.50	1.25	0.26	2.25	0.23	0.51	1.04	0.30	2.08	0.26	0.56	1.26	0.27	2.35	2.23
22	27	Otter Tail	Yes	No	Yes	0.66	0.39	0.62	0.51	2.18	0.60	0.42	0.87	0.45	2.34	0.73	1.01	1.26	1.23	4.23	2.92
23	30	Pinnacle	Yes	Yes	Yes	0.16	1.28	2.77	0.57	4.78	0.27	1.71	3.07	-0.17	4.88	0.32	1.91	3.00	0.24	5.47	5.04
24	33	Public Serv.	Yes	No	No	1.08	0.58	0.98	0.64	3.28	1.03	0.79	0.96	0.65	3.43	1.26	0.70	0.98	0.69	3.63	3.45
25	34	Sempra	Yes	Yes	Yes	1.78	0.85	2.00	1.34	5.97	2.53	1.58	1.31	1.88	7.30	2.95	1.63	1.70	2.16	8.44	7.24
26	35	Southern	Yes	No	No	0.75	0.85	1.25	0.32	3.17	0.81	0.75	1.18	0.51	3.25	1.09	0.67	1.22	0.44	3.42	3.28
27	36	WEC	Yes	Yes	Yes	1.33	0.74	0.74	0.77	3.58	1.43	0.76	0.84	0.76	3.79	1.61	0.87	0.92	0.71	4.11	3.83
28	37	Xcel	Yes	No	Yes	0.61	0.46	1.01	0.56	2.64	0.56	0.54	1.14	0.54	2.78	0.67	0.58	1.13	0.58	2.96	2.79
		No. of Peers:	26	12	17																

Abbreviated Utility	22 2022 Q1	23 2022 Q2	24 2022 Q3	25 2022 Q4	26 2022 Yr	27 2023 Q1	28 2023 Q2	29 2023 Q3	30 2023 Q4	31 2023 Yr	32 2024 Yr	33 2025 Yr	34 2026 Yr	35 2027 Yr	36 VL 2026 - 28 Average	37 VL EPS Growth 2025 - 27 vs. 2019 - 21	Screen #	
Allete	1.24	0.67	0.59	0.90	3.40	1.02	0.83	0.80	1.05	3.70	4.09	4.52	5.00	5.48	5.00	7.1%	1	1
Alliant	0.77	0.63	0.90	0.43	2.73	0.65	0.63	1.05	0.52	2.85	3.14	3.45	3.80	4.15	3.80	7.4%	2	2
Ameren	0.97	0.80	1.74	0.63	4.14	1.00	0.80	1.90	0.65	4.35	4.70	5.09	5.50	5.91	5.50	7.5%	3	3
AEP	1.22	1.20	1.62	1.05	5.09	1.11	1.25	1.75	1.24	5.35	5.80	6.28	6.80	7.32	6.80	7.2%	4	4
Avista	0.99	0.16	-0.08	1.05	2.12	1.10	0.27	0.13	0.80	2.30	2.51	2.75	3.00	3.25	3.00	4.4%	6	5
Black Hills	1.82	0.52	0.54	1.11	3.99	1.70	0.40	0.55	1.10	3.75	4.20	4.69	5.25	5.81	5.25	6.1%	7	6
CenterPoint	0.82	0.28	0.30	0.10	1.50	0.49	0.35	0.50	0.31	1.65	1.74	1.84	1.95	2.06	1.95	7.8%	8	7
CMS	1.20	0.50	0.56	0.58	2.84	0.69	0.70	0.80	0.86	3.05	3.27	3.50	3.75	4.00	3.75	6.7%	9	8
Consol Ed	1.47	0.64	1.63	0.81	4.55	1.59	0.67	1.71	0.88	4.85	5.21	5.59	6.00	6.41	6.00	5.7%	10	9
Dominion	1.18	0.77	1.11	1.06	4.12	1.01	0.79	1.13	1.07	4.00	4.31	4.64	5.00	5.36	5.00	4.3%	11	10
Duke	1.30	1.14	1.78	1.11	5.33	1.30	1.15	2.00	1.20	5.65	6.07	6.52	7.00	7.48	7.00	5.3%	13	11
Edison Int'l	0.22	0.63	-0.33	1.09	1.61	1.00	0.90	1.60	1.20	4.70	5.22	5.80	6.45	7.10	6.45	16.5%	14	12
Entergy	1.36	0.78	2.74	0.51	5.39	1.47	0.80	2.78	0.80	5.85	6.06	6.28	6.50	6.72	6.50	-0.5%	15	13
Evergy	0.53	0.84	1.86	0.03	3.26	0.62	0.85	2.00	0.18	3.65	4.01	4.41	4.85	5.29	4.85	7.6%	16	14
Eversource	1.30	0.86	1.01	0.92	4.09	1.35	0.90	1.10	1.00	4.35	4.73	5.15	5.60	6.05	5.60	7.4%	17	15
Exelon	0.64	0.44	0.75	0.43	2.26	0.65	0.45	0.80	0.50	2.40	2.59	2.78	3.00	3.22	3.00	-0.5%	18	16
IDACORP	0.91	1.27	2.10	0.83	5.11	0.90	1.30	2.00	0.90	5.10	5.47	5.87	6.30	6.73	6.30	5.0%	22	17
MGE	0.95	0.60	0.95	0.50	3.00	1.00	0.65	1.00	0.50	3.15	3.26	3.38	3.50	3.62	3.50	4.6%	23	18
NextEra	0.74	0.81	0.85	0.51	2.91	0.84	0.82	0.95	0.54	3.15	3.52	3.94	4.40	4.86	4.40	11.7%	24	19
NorthWesten	1.08	0.58	0.47	1.16	3.29	1.14	0.60	0.57	1.14	3.45	3.67	3.90	4.15	4.40	4.15	3.3%	25	20
OGE	0.33	0.36	1.31	0.25	2.25	0.19	0.44	1.16	0.21	2.00	2.33	2.71	3.15	3.59	3.15	6.0%	26	21
Otter Tail	1.72	2.05	2.01	1.00	6.78	1.49	1.50	1.01	0.80	4.80	4.38	4.00	3.65	3.30	3.65	3.8%	27	22
Pinnacle	0.15	1.45	2.88	-0.21	4.27	0.15	1.35	2.75	-0.10	4.15	4.61	5.13	5.70	6.27	5.70	2.1%	30	23
Public Serv.	1.33	0.64	0.86	0.64	3.47	1.39	0.65	0.87	0.64	3.55	3.84	4.16	4.50	4.84	4.50	4.5%	33	24
Sempra	2.91	1.98	1.97	2.35	9.21	2.90	1.80	1.90	2.40	9.00	9.91	10.90	12.00	13.10	12.00	8.8%	34	25
Southern	0.97	1.07	1.31	0.26	3.61	0.79	0.95	1.36	0.55	3.65	4.09	4.59	5.15	5.71	5.15	7.8%	35	26
WEC	1.79	0.91	0.96	0.80	4.46	1.61	1.00	1.14	0.85	4.60	5.00	5.43	5.90	6.37	5.90	7.5%	36	27
Xcel	0.70	0.60	1.18	0.69	3.17	0.75	0.65	1.25	0.70	3.35	3.63	3.93	4.25	4.57	4.25	7.2%	37	28

Note: MGE Was Not Covered by VL as of Mar 1, 2023, VL Data Shown is from March 11, 2022 VL Sheet

	Mean
Company Screen	6.1%
Staff Screen	6.0%
Staff Sensitivity Screen	6.0%

$$B_U = \frac{B_L}{[1 + (1 - T_C) \times (D/E)]}$$

	1	2	3	4		5	6	7	8	9	10	11	13	14	15	19	20	22	24	26	27		
							Yahoo Finance $ Stock Closing Price 1st Trading Day of Month					VL	VL Cap Structure Percentages										
	Screen #	Abbreviated Utility	PGE Yes	Staff No	LT Debt Staff Sensitivity	Ticker	Jun. 6/1/2023	Jul. 7/1/2023	Aug. 8/1/2023	*3-Day Avg $ Stock Price*	*Div Yield at Recent Price*	*2023 Return on Common Equity*	2023 % LT Debt	2023 Common Equity	2023 Preferred Stock	VL Beta	VL 2023 Tax Rate	2023 Unlevered Beta	2023 Relevered Beta *Equity at 50.0%*	Equity Risk Premium	*Hamada 2023 Adjustment Equity at 50.0%*	Screen #	
1	1	Allete	Yes	No	No	ALE	57.97	57.43	57.60	57.67	4.5%	8.0%	39.5	60.5	0.0	0.90	0.0%	0.54	109%	4.50%	0.85%	1	1
2	2	Alliant	Yes	Yes	Yes	LNT	52.48	53.74	51.76	52.66	3.2%	10.5%	53.5	46.5	0.0	0.85	1.0%	0.40	79%	4.50%	-0.27%	2	2
3	3	Ameren	Yes	Yes	Yes	AEE	81.67	85.67	84.39	83.91	2.8%	11.0%	55.5	44.0	0.5	0.85	12.0%	0.40	75%	4.50%	-0.43%	3	3
4	4	AEP	Yes	No	Yes	AEP	84.20	84.74	84.50	84.48	3.8%	10.0%	58.0	42.0	0.0	0.75	21.0%	0.36	64%	4.50%	-0.49%	4	4
5	6	Avista	Yes	Yes	Yes	AVA	39.27	38.64	38.68	38.86	4.5%	7.5%	50.5	49.5	0.0	0.90	15.0%	0.48	89%	4.50%	-0.04%	6	5
6	7	Black Hills	Yes	No	Yes	BKH	60.26	60.33	59.31	59.97	4.0%	8.0%	55.5	45.5	-1.0	0.95	8.5%	0.45	87%	4.50%	-0.37%	7	6
7	8	CenterPoint	Yes	No	No	CNP	29.15	30.09	29.74	29.66	2.4%	10.0%	56.0	41.0	3.0	1.10	20.0%	0.51	92%	4.50%	-0.81%	8	7
8	9	CMS	Yes	No	No	CMS	58.75	61.07	60.28	60.03	3.1%	12.0%	63.5	35.5	1.0	0.80	11.0%	0.31	58%	4.50%	-1.00%	9	8
9	10	Consol Ed	No	Yes	Yes	ED	90.40	94.86	93.33	92.86	3.4%	8.5%	48.5	51.5	0.0	0.75	18.0%	0.42	77%	4.50%	0.09%	10	9
10	11	Dominion	Yes	No	No	D	51.79	53.55	52.34	52.56	5.1%	12.0%	57.5	39.5	3.0	0.85	16.0%	0.37	68%	4.50%	-0.75%	11	10
11	13	Duke	Yes	No	Yes	DUK	89.74	93.62	92.53	91.96	4.3%	9.0%	58.5	40.0	1.5	0.85	9.0%	0.36	69%	4.50%	-0.74%	13	11
12	14	Edison Int'l	Yes	No	No	EIX	69.45	71.96	71.54	70.98	4.0%	12.0%	61.5	29.5	9.0	0.95	5.0%	0.29	57%	4.50%	-1.73%	14	12
13	15	Entergy	Yes	No	No	ETR	97.37	102.7	101.40	100.49	4.1%	9.0%	64.5	35.5	0.0	0.90	23.0%	0.38	66%	4.50%	-1.06%	15	13
14	16	Evergy	Yes	Yes	Yes	EVRG	58.42	59.97	59.71	59.37	3.9%	9.0%	51.5	48.5	0.0	0.90	9.0%	0.46	87%	4.50%	-0.12%	16	14
15	17	Eversource	No	Yes	Yes	ES	70.92	72.33	69.8	71.02	3.6%	9.5%	56.5	43.0	0.5	0.90	24.0%	0.45	79%	4.50%	-0.50%	17	15
16	18	Exelon	Yes	No	No	EXC	40.74	41.86	41.50	41.37	3.3%	9.5%	61.0	39.0	0.0	0.00	15.0%	0.00	0%	4.50%	0.00%	18	16
17	22	IDACORP	Yes	Yes	Yes	IDA	102.60	102.82	101.88	102.43	3.0%	9.0%	46.5	53.5	0.0	0.80	13.0%	0.46	85%	4.50%	0.23%	22	17
18	23	MGE	Yes	No	No	MGEE	79.11	80.24	79.84	79.73	2.0%	10.0%	41.0	59.0	0.0	0.75	16.0%	0.47	87%	4.50%	0.55%	23	18
19	24	NextEra	Yes	No	No	NEE	74.20	73.3	71.91	73.14	2.3%	14.0%	57.0	43.0	0.0	0.95	18.0%	0.46	83%	4.50%	-0.55%	24	19
20	25	NorthWesten	Yes	Yes	Yes	NWE	56.76	56.47	55.95	56.39	4.5%	7.0%	47.5	52.5	0.0	0.90	3.0%	0.48	94%	4.50%	0.20%	25	20
21	26	OGE	Yes	Yes	Yes	OGE	35.91	36.15	36.18	36.08	4.5%	12.0%	52.0	48.0	0.0	1.00	12.0%	0.51	96%	4.50%	-0.17%	26	21
22	27	Otter Tail	Yes	No	Yes	OTTR	78.96	81.01	89.67	83.21	2.0%	13.5%	41.5	58.5	0.0	0.85	20.0%	0.54	98%	4.50%	0.57%	27	22
23	30	Pinnacle	Yes	Yes	Yes	PNW	81.46	82.82	82.57	82.28	4.2%	7.5%	56.0	44.0	0.0	0.90	13.5%	0.43	80%	4.50%	-0.45%	30	23
24	33	Public Serv.	Yes	No	No	PEG	62.61	63.12	63.14	62.96	3.4%	12.5%	54.0	46.0	0.0	0.90	20.0%	0.46	84%	4.50%	-0.29%	33	24
25	34	Sempra	Yes	Yes	Yes	SRE	145.59	149.02	146.87	147.16	3.1%	11.0%	50.5	48.0	1.5	0.95	19.0%	0.51	92%	4.50%	-0.15%	34	25
26	35	Southern	Yes	No	No	SO	70.25	72.34	70.97	71.19	3.8%	13.0%	64.0	36.0	0.0	0.90	15.0%	0.36	66%	4.50%	-1.07%	35	26
27	36	WEC	Yes	Yes	Yes	WEC	88.24	89.86	89.52	89.21	3.3%	12.5%	55.0	44.5	0.5	0.80	19.0%	0.40	72%	4.50%	-0.36%	36	27
28	37	Xcel	Yes	No	Yes	XEL	62.17	62.73	62.88	62.59	3.1%	10.5%	58.0	42.0	0.0	0.80	0.0%	0.34	67%	4.50%	-0.58%	37	28
		No. of Peers:	26	9	12																		

	Mean (Common Equity)	Mean (Hamada Adjustment)
Company Screen	45.1%	-0.35%
Staff Screen	47.8%	-0.16%
Staff Sensitivity Screen	47.1%	-0.21%

Unlevered Beta = Levered Beta / (1 + ((1 – Tax Rate) x (Debt/Equity)))

Levered Beta = Unlevered Beta x (1 + ((1 – Tax Rate) x (Debt/Equity)))

Note: MGE Was Not Covered by VL as of Mar 1, 2023, VL Data Shown is from March 11, 2022 VL Sheet

CASE: UE 416
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2903

ROE – Three-Stage DCF:
Models X and Y

August 22, 2023

4.05% Annual Growth Rate - Stage 3

Dividend Growth with Terminal Value as Perpetuity

E.O.Y. Cash Flows — Staff — Model X

	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		
										Initial Stage					Transition Stage					Final Stage																							
	Screen #	Abbreviated Utility	PGE Yes	Staff No	LT Debt Staff Sensitivity	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2046 Terminal Value	2049 Div	2049 Perpetuity	Screen #	
1	1	Allete	Yes	No	No	8.6%	28.8%	0.00	(57.67)	2.60	2.71	2.80	2.90	3.00	3.10	3.31	3.50	3.67	3.82	3.98	4.14	4.31	4.48	4.66	4.85	5.05	5.25	5.47	5.69	5.92	6.16	6.41	6.67	6.94	7.22	7.51	7.81	8.13	199.97	8.46	191.51	1	1
2	2	Alliant	Yes	Yes	Yes	8.1%	34.0%	0.00	(52.66)	1.71	1.81	1.96	2.12	2.29	2.46	2.70	2.91	3.08	3.20	3.33	3.46	3.60	3.75	3.90	4.06	4.22	4.40	4.57	4.76	4.95	5.15	5.36	5.58	5.80	6.04	6.28	6.54	6.80	187.26	7.08	180.18	2	2
3	3	Ameren	Yes	Yes	Yes	7.8%	37.1%	0.00	(83.91)	2.36	2.52	2.76	3.02	3.30	3.58	3.96	4.29	4.55	4.74	4.93	5.13	5.34	5.55	5.78	6.01	6.25	6.51	6.77	7.05	7.33	7.63	7.94	8.26	8.59	8.94	9.30	9.68	10.07	298.96	10.48	288.48	3	3
4	4	AEP	Yes	No	No	8.6%	29.9%	0.00	(84.48)	3.17	3.35	3.60	3.87	4.16	4.45	4.85	5.21	5.51	5.73	5.96	6.21	6.46	6.72	6.99	7.27	7.57	7.88	8.19	8.53	8.87	9.23	9.61	9.99	10.40	10.82	11.26	11.71	12.19	301.57	12.68	288.89	4	4
5	6	Avista	Yes	Yes	Yes	9.0%	26.3%	0.00	(38.86)	1.76	1.84	1.94	2.04	2.15	2.26	2.43	2.59	2.73	2.84	2.96	3.08	3.20	3.33	3.47	3.61	3.75	3.90	4.06	4.23	4.40	4.58	4.76	4.95	5.15	5.36	5.58	5.81	6.04	137.41	6.29	131.12	6	5
6	7	Black Hills	Yes	No	Yes	8.8%	28.7%	0.00	(59.97)	2.41	2.53	2.70	2.88	3.07	3.26	3.54	3.80	4.01	4.17	4.34	4.51	4.70	4.89	5.08	5.29	5.51	5.73	5.96	6.20	6.45	6.71	6.99	7.27	7.56	7.87	8.19	8.52	8.86	213.34	9.22	204.11	7	6
7	8	CenterPoint	Yes	No	No	6.9%	46.4%	0.00	(29.66)	0.72	0.77	0.83	0.89	0.95	1.01	1.07	1.12	1.18	1.22	1.27	1.32	1.38	1.43	1.49	1.55	1.62	1.68	1.75	1.82	1.89	1.97	2.05	2.13	2.22	2.31	2.40	2.50	2.60	101.77	2.71	99.06	8	7
8	9	CMS	Yes	No	No	7.6%	38.9%	0.00	(60.03)	1.84	1.95	2.06	2.18	2.30	2.42	2.63	2.82	2.97	3.09	3.22	3.35	3.49	3.63	3.77	3.93	4.09	4.25	4.42	4.60	4.79	4.98	5.18	5.39	5.61	5.84	6.08	6.32	6.58	208.93	6.84	202.08	9	8
9	10	Consol Ed	No	Yes	Yes	7.8%	36.5%	0.00	(92.86)	3.16	3.24	3.43	3.64	3.86	4.08	4.37	4.64	4.88	5.07	5.28	5.49	5.72	5.95	6.19	6.44	6.70	6.97	7.25	7.55	7.85	8.17	8.50	8.85	9.21	9.58	9.97	10.37	10.79	322.77	11.23	311.54	10	9
10	11	Dominion	Yes	No	No	9.2%	24.8%	0.00	(52.56)	2.67	2.67	2.82	2.99	3.16	3.33	3.46	3.60	3.74	3.89	4.05	4.21	4.38	4.56	4.74	4.94	5.14	5.34	5.56	5.79	6.02	6.26	6.52	6.78	7.06	7.34	7.64	7.95	8.27	182.66	8.61	174.06	11	10
11	13	Duke	Yes	No	Yes	8.1%	33.0%	0.00	(91.96)	3.98	4.06	4.14	4.22	4.30	4.38	4.63	4.86	5.08	5.29	5.50	5.73	5.96	6.20	6.45	6.71	6.98	7.27	7.56	7.87	8.19	8.52	8.86	9.22	9.59	9.98	10.39	10.81	11.25	312.92	11.70	301.22	13	11
12	14	Edison Int'l	Yes	No	No	8.8%	28.5%	0.00	(70.98)	2.84	2.95	3.17	3.40	3.65	3.90	4.24	4.55	4.81	5.00	5.20	5.41	5.63	5.86	6.10	6.35	6.60	6.87	7.15	7.44	7.74	8.05	8.38	8.72	9.07	9.44	9.82	10.22	10.63	253.56	11.06	242.50	14	12
13	15	Entergy	Yes	No	No	8.5%	30.0%	0.00	(100.49)	4.10	4.30	4.52	4.75	5.00	5.25	5.66	6.03	6.35	6.60	6.87	7.15	7.44	7.74	8.06	8.38	8.72	9.07	9.44	9.82	10.22	10.64	11.07	11.51	11.98	12.47	12.97	13.50	14.04	352.77	14.61	338.16	15	13
14	16	Evergy	Yes	Yes	Yes	8.8%	28.4%	0.00	(59.37)	2.33	2.53	2.69	2.87	3.05	3.23	3.54	3.80	4.02	4.19	4.35	4.53	4.71	4.91	5.10	5.31	5.53	5.75	5.98	6.23	6.48	6.74	7.01	7.30	7.59	7.90	8.22	8.55	8.90	212.01	9.26	202.75	16	14
15	17	Eversource	No	Yes	Yes	8.7%	29.8%	0.00	(71.02)	2.55	2.70	2.94	3.20	3.48	3.76	4.13	4.45	4.71	4.91	5.10	5.31	5.53	5.75	5.98	6.22	6.48	6.74	7.01	7.30	7.59	7.90	8.22	8.55	8.90	9.26	9.63	10.02	10.43	255.77	10.85	244.92	17	15
16	18	Exelon	Yes	No	No	8.0%	35.2%	0.00	(41.37)	1.35	1.44	1.55	1.67	1.80	1.93	2.05	2.17	2.27	2.37	2.46	2.56	2.66	2.77	2.88	3.00	3.12	3.25	3.38	3.52	3.66	3.81	3.96	4.12	4.29	4.46	4.64	4.83	5.03	144.78	5.23	139.55	18	16
17	22	IDACORP	Yes	Yes	Yes	7.9%	36.4%	0.00	(102.43)	3.04	3.20	3.49	3.81	4.15	4.49	4.93	5.31	5.63	5.85	6.09	6.34	6.60	6.86	7.14	7.43	7.73	8.04	8.37	8.71	9.06	9.43	9.81	10.21	10.62	11.05	11.50	11.96	12.45	363.86	12.95	350.91	22	17
18	23	MGE	Yes	No	No	N/A	N/A	N/A	(79.73)	1.59	1.66	1.74	1.82	1.90	1.98	2.14	2.27	2.39	2.49	2.59	2.69	2.80	2.92	3.04	3.16	3.29	3.42	3.56	3.70	3.85	4.01	4.17	4.34	4.51	4.70	4.89	5.09	5.29	#VALUE!	5.51	#VALUE!	23	18
19	24	NextEra	Yes	No	No	7.9%	37.6%	0.00	(73.14)	1.70	1.87	2.12	2.41	2.74	3.07	3.47	3.82	4.09	4.26	4.43	4.61	4.79	4.99	5.19	5.40	5.62	5.85	6.08	6.33	6.59	6.85	7.13	7.42	7.72	8.03	8.36	8.70	9.05	266.26	9.41	256.84	24	19
20	25	NorthWestern	Yes	Yes	Yes	8.3%	31.2%	0.00	(56.39)	2.52	2.56	2.63	2.69	2.76	2.83	3.00	3.15	3.30	3.44	3.57	3.72	3.87	4.03	4.19	4.36	4.54	4.72	4.91	5.11	5.32	5.53	5.76	5.99	6.23	6.48	6.75	7.02	7.30	193.09	7.60	185.49	25	20
21	26	OGE	Yes	Yes	Yes	8.6%	29.4%	0.00	(36.08)	1.64	1.66	1.72	1.78	1.85	1.92	2.04	2.15	2.25	2.34	2.44	2.54	2.64	2.75	2.86	2.98	3.10	3.22	3.35	3.49	3.63	3.78	3.93	4.09	4.25	4.43	4.61	4.79	4.99	124.77	5.19	119.58	26	21
22	27	Otter Tail	Yes	No	Yes	N/A	N/A	N/A	(83.21)	1.65	1.76	1.90	2.04	2.20	2.36	2.58	2.77	2.93	3.05	3.17	3.30	3.44	3.58	3.72	3.87	4.03	4.19	4.36	4.54	4.72	4.91	5.11	5.32	5.54	5.76	5.99	6.24	6.49	#VALUE!	6.75	#VALUE!	27	22
23	30	Pinnacle	Yes	Yes	Yes	8.0%	33.6%	0.00	(82.28)	3.42	3.48	3.57	3.66	3.75	3.84	4.08	4.31	4.51	4.70	4.89	5.08	5.29	5.50	5.73	5.96	6.20	6.45	6.71	6.99	7.27	7.56	7.87	8.19	8.52	8.86	9.22	9.60	9.99	281.42	10.39	271.03	30	23
24	33	Public Serv.	Yes	No	No	8.2%	33.5%	0.00	(62.96)	2.16	2.28	2.44	2.61	2.80	2.99	3.25	3.48	3.68	3.83	3.98	4.14	4.31	4.48	4.67	4.85	5.05	5.26	5.47	5.69	5.92	6.16	6.41	6.67	6.94	7.22	7.51	7.82	8.13	222.45	8.46	213.99	33	24
25	34	Sempra	Yes	Yes	Yes	8.0%	35.7%	0.00	(147.16)	4.58	4.76	5.17	5.62	6.10	6.58	7.20	7.75	8.20	8.53	8.88	9.24	9.61	10.00	10.41	10.83	11.27	11.72	12.20	12.69	13.21	13.74	14.30	14.88	15.48	16.10	16.76	17.44	18.14	521.91	18.88	503.03	34	25
26	35	Southern	Yes	No	No	7.9%	35.1%	0.00	(71.19)	2.70	2.78	2.88	2.99	3.10	3.21	3.42	3.62	3.80	3.96	4.12	4.28	4.46	4.64	4.82	5.02	5.22	5.43	5.65	5.88	6.12	6.37	6.63	6.90	7.17	7.47	7.77	8.08	8.41	244.96	8.75	236.21	35	26
27	36	WEC	Yes	Yes	Yes	8.0%	34.8%	0.00	(89.21)	2.91	3.12	3.33	3.56	3.80	4.04	4.42	4.76	5.04	5.24	5.46	5.68	5.91	6.15	6.39	6.65	6.92	7.20	7.49	7.80	8.11	8.44	8.78	9.14	9.51	9.90	10.30	10.71	11.15	315.05	11.60	303.45	36	27
28	37	Xcel	Yes	No	Yes	8.1%	34.6%	0.00	(62.59)	1.95	2.08	2.26	2.45	2.66	2.87	3.16	3.41	3.62	3.76	3.92	4.07	4.24	4.41	4.59	4.78	4.97	5.17	5.38	5.60	5.82	6.06	6.30	6.56	6.83	7.10	7.39	7.69	8.00	223.12	8.32	214.80	37	28

No. of Peers:	PGE	Staff	LT Debt Staff Sensitivity
	26	12	17

IRR	Terminal Value as % of NPV_{DIV} (Mean)	NPV @ IRR	
8.24%	33.00%	0.00%	Company Screen
8.25%	32.77%	0.00%	Staff Screen
8.29%	32.46%	0.00%	Staff Sensitivity Screen

B.O.Y. Cash Flows — Staff — Model X

	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		
										Initial Stage					Transition Stage					Final Stage																							
	Screen #	Abbreviated Utility	PGE Yes	Staff No	LT Debt Staff Sensitivity	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2046 Terminal Value	2049 Div	2049 Perpetuity	Screen #	
1	1	Allete	Yes	No	No	8.8%	27.4%	0.00	(57.67)	2.71	2.80	2.90	3.00	3.10	3.31	3.50	3.67	3.82	3.98	4.14	4.31	4.48	4.66	4.85	5.05	5.25	5.47	5.69	5.92	6.16	6.41	6.67	6.94	7.22	7.51	7.81	8.13	8.46	200.21	8.80	191.41	1	1
2	2	Alliant	Yes	Yes	Yes	8.3%	32.1%	0.00	(52.66)	1.81	1.96	2.12	2.29	2.46	2.70	2.91	3.08	3.20	3.33	3.46	3.60	3.75	3.90	4.06	4.22	4.40	4.57	4.76	4.95	5.15	5.36	5.58	5.80	6.04	6.28	6.54	6.80	7.08	186.34	7.37	178.98	2	2
3	3	Ameren	Yes	Yes	Yes	8.0%	35.1%	0.00	(83.91)	2.52	2.76	3.02	3.30	3.58	3.96	4.29	4.55	4.74	4.93	5.13	5.34	5.55	5.78	6.01	6.25	6.51	6.77	7.05	7.33	7.63	7.94	8.26	8.59	8.94	9.30	9.68	10.07	10.48	297.16	10.90	286.26	3	3
4	4	AEP	Yes	No	No	8.8%	28.0%	0.00	(84.48)	3.35	3.60	3.87	4.16	4.45	4.85	5.21	5.51	5.73	5.96	6.21	6.46	6.72	6.99	7.27	7.57	7.88	8.19	8.53	8.87	9.23	9.61	9.99	10.40	10.82	11.26	11.71	12.19	12.68	300.21	13.20	287.01	4	4
5	6	Avista	Yes	Yes	Yes	9.3%	24.8%	0.00	(38.86)	1.84	1.94	2.04	2.15	2.26	2.43	2.59	2.73	2.84	2.96	3.08	3.20	3.33	3.47	3.61	3.75	3.90	4.06	4.23	4.40	4.58	4.76	4.95	5.15	5.36	5.58	5.81	6.04	6.29	137.19	6.54	130.65	6	5
6	7	Black Hills	Yes	No	Yes	9.0%	26.9%	0.00	(59.97)	2.53	2.70	2.88	3.07	3.26	3.54	3.80	4.01	4.17	4.34	4.51	4.70	4.89	5.08	5.29	5.51	5.73	5.96	6.20	6.45	6.71	6.99	7.27	7.56	7.87	8.19	8.52	8.86	9.22	212.61	9.60	203.01	7	6
7	8	CenterPoint	Yes	No	No	7.0%	44.7%	0.00	(29.66)	0.77	0.83	0.89	0.95	1.01	1.07	1.12	1.18	1.22	1.27	1.32	1.38	1.43	1.49	1.55	1.62	1.68	1.75	1.82	1.89	1.97	2.05	2.13	2.22	2.31	2.40	2.50	2.60	2.71	101.53	2.82	98.72	8	7
8	9	CMS	Yes	No	No	7.7%	37.2%	0.00	(60.03)	1.95	2.06	2.18	2.30	2.42	2.63	2.82	2.97	3.09	3.22	3.35	3.49	3.63	3.77	3.93	4.09	4.25	4.42	4.60	4.79	4.98	5.18	5.39	5.61	5.84	6.08	6.32	6.58	6.84	208.46	7.12	201.34	9	8
9	10	Consol Ed	No	Yes	Yes	8.0%	34.9%	0.00	(92.86)	3.24	3.43	3.64	3.86	4.08	4.37	4.64	4.88	5.07	5.28	5.49	5.72	5.95	6.19	6.44	6.70	6.97	7.25	7.55	7.85	8.17	8.50	8.85	9.21	9.58	9.97	10.37	10.79	11.23	322.38	11.68	310.70	10	9
10	11	Dominion	Yes	No	No	9.4%	23.5%	0.00	(52.56)	2.67	2.82	2.99	3.16	3.33	3.46	3.60	3.74	3.89	4.05	4.21	4.38	4.56	4.74	4.94	5.14	5.34	5.56	5.79	6.02	6.26	6.52	6.78	7.06	7.34	7.64	7.95	8.27	8.61	182.94	8.95	173.99	11	10
11	13	Duke	Yes	No	Yes	8.2%	31.7%	0.00	(91.96)	4.06	4.14	4.22	4.30	4.38	4.63	4.86	5.08	5.29	5.50	5.73	5.96	6.20	6.45	6.71	6.98	7.27	7.56	7.87	8.19	8.52	8.86	9.22	9.59	9.98	10.39	10.81	11.25	11.70	314.20	12.18	302.03	13	11
12	14	Edison Int'l	Yes	No	No	9.0%	26.7%	0.00	(70.98)	2.95	3.17	3.40	3.65	3.90	4.24	4.55	4.81	5.00	5.20	5.41	5.63	5.86	6.10	6.35	6.60	6.87	7.15	7.44	7.74	8.05	8.38	8.72	9.07	9.44	9.82	10.22	10.63	11.06	252.58	11.51	241.08	14	12
13	15	Entergy	Yes	No	No	8.7%	28.3%	0.00	(100.49)	4.30	4.52	4.75	5.00	5.25	5.66	6.03	6.35	6.60	6.87	7.15	7.44	7.74	8.06	8.38	8.72	9.07	9.44	9.82	10.22	10.64	11.07	11.51	11.98	12.47	12.97	13.50	14.04	14.61	352.26	15.20	337.05	15	13
14	16	Evergy	Yes	Yes	Yes	9.0%	26.6%	0.00	(59.37)	2.53	2.69	2.87	3.05	3.23	3.54	3.80	4.02	4.19	4.35	4.53	4.71	4.91	5.10	5.31	5.53	5.75	5.98	6.23	6.48	6.74	7.01	7.30	7.59	7.90	8.22	8.55	8.90	9.26	211.03	9.63	201.40	16	14
15	17	Eversource	No	Yes	Yes	8.9%	27.8%	0.00	(71.02)	2.70	2.94	3.20	3.48	3.76	4.13	4.45	4.71	4.91	5.10	5.31	5.53	5.75	5.98	6.22	6.48	6.74	7.01	7.30	7.59	7.90	8.22	8.55	8.90	9.26	9.63	10.02	10.43	10.85	254.23	11.29	242.94	17	15
16	18	Exelon	Yes	No	No	8.1%	33.4%	0.00	(41.37)	1.44	1.55	1.67	1.80	1.93	2.05	2.17	2.27	2.37	2.46	2.56	2.66	2.77	2.88	3.00	3.12	3.25	3.38	3.52	3.66	3.81	3.96	4.12	4.29	4.46	4.64	4.83	5.03	5.23	144.26	5.44	138.81	18	16
17	22	IDACORP	Yes	Yes	Yes	8.1%	34.4%	0.00	(102.43)	3.20	3.49	3.81	4.15	4.49	4.93	5.31	5.63	5.85	6.09	6.34	6.60	6.86	7.14	7.43	7.73	8.04	8.37	8.71	9.06	9.43	9.81	10.21	10.62	11.05	11.50	11.96	12.45	12.95	361.95	13.48	348.48	22	17
18	23	MGE	Yes	No	No	N/A	N/A	N/A	(79.73)	1.66	1.74	1.82	1.90	1.98	2.14	2.27	2.39	2.49	2.59	2.69	2.80	2.92	3.04	3.16	3.29	3.42	3.56	3.70	3.85	4.01	4.17	4.34	4.51	4.70	4.89	5.09	5.29	5.51	#VALUE!	5.73	#VALUE!	23	18
19	24	NextEra	Yes	No	No	8.1%	35.2%	0.00	(73.14)	1.87	2.12	2.41	2.74	3.07	3.47	3.82	4.09	4.26	4.43	4.61	4.79	4.99	5.19	5.40	5.62	5.85	6.08	6.33	6.59	6.85	7.13	7.42	7.72	8.03	8.36	8.70	9.05	9.41	263.64	9.80	253.85	24	19
20	25	NorthWestern	Yes	Yes	Yes	8.5%	29.9%	0.00	(56.39)	2.56	2.63	2.69	2.76	2.83	3.00	3.15	3.30	3.44	3.57	3.72	3.87	4.03	4.19	4.36	4.54	4.72	4.91	5.11	5.32	5.53	5.76	5.99	6.23	6.48	6.75	7.02	7.30	7.60	193.77	7.91	185.86	25	20
21	26	OGE	Yes	Yes	Yes	8.7%	28.0%	0.00	(36.08)	1.66	1.72	1.78	1.85	1.92	2.04	2.15	2.25	2.34	2.44	2.54	2.64	2.75	2.86	2.98	3.10	3.22	3.35	3.49	3.63	3.78	3.93	4.09	4.25	4.43	4.61	4.79	4.99	5.19	125.05	5.40	119.65	26	21
22	27	Otter Tail	Yes	No	Yes	6.7%	49.6%	0.00	(83.21)	1.76	1.90	2.04	2.20	2.36	2.58	2.77	2.93	3.05	3.17	3.30	3.44	3.58	3.72	3.87	4.03	4.19	4.36	4.54	4.72	4.91	5.11	5.32	5.54	5.76	5.99	6.24	6.49	6.75	286.19	7.02	279.16	27	22
23	30	Pinnacle	Yes	Yes	Yes	8.2%	32.3%	0.00	(82.28)	3.48	3.57	3.66	3.75	3.84	4.08	4.31	4.51	4.70	4.89	5.08	5.29	5.50	5.73	5.96	6.20	6.45	6.71	6.99	7.27	7.56	7.87	8.19	8.52	8.86	9.22	9.60	9.99	10.39	282.30	10.81	271.49	30	23
24	33	Public Serv.	Yes	No	No	8.4%	31.7%	0.00	(62.96)	2.28	2.44	2.61	2.80	2.99	3.25	3.48	3.68	3.83	3.98	4.14	4.31	4.48	4.67	4.85	5.05	5.26	5.47	5.69	5.92	6.16	6.41	6.67	6.94	7.22	7.51	7.82	8.13	8.46	221.62	8.81	212.82	33	24
25	34	Sempra	Yes	Yes	Yes	8.1%	33.8%	0.00	(147.16)	4.76	5.17	5.62	6.10	6.58	7.20	7.75	8.20	8.53	8.88	9.24	9.61	10.00	10.41	10.83	11.27	11.72	12.20	12.69	13.21	13.74	14.30	14.88	15.48	16.10	16.76	17.44	18.14	18.88	519.52	19.64	499.88	34	25
26	35	Southern	Yes	No	No	8.1%	33.6%	0.00	(71.19)	2.78	2.88	2.99	3.10	3.21	3.42	3.62	3.80	3.96	4.12	4.28	4.46	4.64	4.82	5.02	5.22	5.43	5.65	5.88	6.12	6.37	6.63	6.90	7.17	7.47	7.77	8.08	8.41	8.75	245.24	9.10	236.14	35	26
27	36	WEC	Yes	Yes	Yes	8.2%	33.0%	0.00	(89.21)	3.12	3.33	3.56	3.80	4.04	4.42	4.76	5.04	5.24	5.46	5.68	5.91	6.15	6.39	6.65	6.92	7.20	7.49	7.80	8.11	8.44	8.78	9.14	9.51	9.90	10.30	10.71	11.15	11.60	313.78	12.07	301.71	36	27
28	37	Xcel	Yes	No	Yes	8.3%	32.6%	0.00	(62.59)	2.08	2.26	2.45	2.66	2.87	3.16	3.41	3.62	3.76	3.92	4.07	4.24	4.41	4.59	4.78	4.97	5.17	5.38	5.60	5.82	6.06	6.30	6.56	6.83	7.10	7.39	7.69	8.00	8.32	221.89	8.66	213.23	37	28

No. of Peers:	PGE	Staff	LT Debt Staff Sensitivity
	26	12	17

IRR	Terminal Value as % of NPV_{DIV} (Mean)	NPV @ IRR	
8.35%	32.01%	0.00%	Company Screen
8.44%	31.04%	0.00%	Staff Screen
8.37%	31.84%	0.00%	Staff Sensitivity Screen

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

	1	2	3	4		5	6	7	8	9		
	Screen #	Abbreviated Utility	PGE Yes	Staff No	LT Debt Staff Sensitivity	Average IRR	Terminal Value as % of NPV_{DIV}	Average 2020- 2024 Dividend Growth Rates EOY	BOY	Average	Screen #	
1	1	Allete	Yes	No	No	8.7%	28.1%	3.6%	3.4%	3.5%	1	1
2	2	Alliant	Yes	Yes	Yes	8.2%	33.0%	7.6%	8.0%	7.8%	2	2
3	3	Ameren	Yes	Yes	Yes	7.9%	36.1%	8.7%	9.2%	9.0%	3	3
4	4	AEP	Yes	No	Yes	8.7%	29.0%	7.0%	7.4%	7.2%	4	4
5	6	Avista	Yes	Yes	Yes	9.1%	25.6%	5.1%	5.3%	5.2%	6	5
6	7	Black Hills	Yes	No	Yes	8.9%	27.8%	6.2%	6.6%	6.4%	7	6
7	8	CenterPoint	Yes	No	No	7.0%	45.6%	7.2%	7.1%	7.2%	8	7
8	9	CMS	Yes	No	No	7.7%	38.1%	5.7%	5.6%	5.7%	9	8
9	10	Consol Ed	No	Yes	Yes	7.9%	35.7%	5.1%	5.9%	5.5%	10	9
10	11	Dominion	Yes	No	No	9.3%	24.1%	4.3%	5.7%	5.0%	11	10
11	13	Duke	Yes	No	Yes	8.2%	32.3%	2.0%	1.9%	1.9%	13	11
12	14	Edison Int'l	Yes	No	No	8.9%	27.6%	6.5%	7.2%	6.9%	14	12
13	15	Entergy	Yes	No	No	8.6%	29.2%	5.1%	5.1%	5.1%	15	13
14	16	Evergy	Yes	Yes	Yes	8.9%	27.5%	7.0%	6.3%	6.6%	16	14
15	17	Eversource	No	Yes	Yes	8.8%	28.8%	8.1%	8.6%	8.4%	17	15
16	18	Exelon	Yes	No	No	8.0%	34.3%	7.5%	7.6%	7.5%	18	16
17	22	IDACORP	Yes	Yes	Yes	8.0%	35.4%	8.1%	8.9%	8.5%	22	17
18	23	MGE	Yes	No	No	N/A	N/A	4.6%	4.6%	4.6%	23	18
19	24	NextEra	Yes	No	No	8.0%	36.4%	12.7%	13.2%	12.9%	24	19
20	25	NorthWestern	Yes	Yes	Yes	8.4%	30.5%	2.3%	2.5%	2.4%	25	20
21	26	OGE	Yes	Yes	Yes	8.7%	28.7%	3.1%	3.6%	3.4%	26	21
22	27	Otter Tail	Yes	No	Yes	6.7%	49.6%	7.5%	7.6%	7.5%	27	22
23	30	Pinnacle	Yes	Yes	Yes	8.1%	33.0%	2.3%	2.5%	2.4%	30	23
24	33	Public Serv.	Yes	No	No	8.3%	32.6%	6.7%	7.0%	6.8%	33	24
25	34	Sempra	Yes	Yes	Yes	8.0%	34.7%	7.4%	8.4%	7.9%	34	25
26	35	Southern	Yes	No	No	8.0%	34.4%	3.5%	3.7%	3.6%	35	26
27	36	WEC	Yes	Yes	Yes	8.1%	33.9%	6.9%	6.7%	6.8%	36	27
28	37	Xcel	Yes	No	Yes	8.2%	33.6%	8.1%	8.4%	8.2%	37	28
		No. of Peers:	26	12	17	Mean						
						8.26%	32.84%	6.02%	Company Screen			
						8.35%	31.90%	5.98%	Staff Screen			
						8.28%	32.66%	6.03%	Staff Sensitivity Screen			

4.05% Annual Growth Rate - Stage 3 | EPS Growth to Determine a Sale Terminal Value | EPS Growth

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

	Screen #	Abbreviated Utility	PGE Peers	Staff Peers	LT Debt Staff Sensitivity	IRR	Terminal Value as % of NPV$_{DIV}$	NPV @ IRR	Recent Price*	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2046 Terminal Value	2049 Div	2049 Sale	2050	Screen #	
	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		
										Initial Stage					Transition Stage					Final Stage																								
1	1	Allete	Yes	No	No	9.3%	34.0%	0.00	(57.67)	2.60	2.71	2.80	2.90	3.00	3.10	3.31	3.50	3.67	3.82	3.98	4.14	4.31	4.48	4.66	4.85	5.05	5.25	5.47	5.69	5.92	6.16	6.41	6.67	6.94	7.22	7.51	7.81	8.13	286.41	8.46	277.95		1	1
				e	e					3.40	3.70	4.09	4.52	5.00	5.48	6.00	6.46	6.84	7.12	7.41	7.71	8.02	8.34	8.68	9.03	9.40	9.78	10.18	10.59	11.02	11.46	11.93	12.41	12.91	13.44	13.98	14.55	15.14		15.75		16.39		
2	2	Alliant	Yes	Yes	Yes	8.7%	38.3%	0.00	(52.66)	1.71	1.81	1.96	2.12	2.29	2.46	2.70	2.91	3.08	3.20	3.33	3.46	3.60	3.75	3.90	4.06	4.22	4.40	4.57	4.76	4.95	5.15	5.36	5.58	5.80	6.04	6.28	6.54	6.80	247.47	7.08	240.39		2	2
				e	e					2.73	2.85	3.14	3.45	3.80	4.15	4.55	4.91	5.20	5.41	5.63	5.86	6.10	6.35	6.60	6.87	7.15	7.44	7.74	8.05	8.38	8.72	9.07	9.44	9.82	10.22	10.63	11.06	11.51		11.98		12.46		
3	3	Ameren	Yes	Yes	Yes	8.3%	40.5%	0.00	(83.91)	2.36	2.52	2.76	3.02	3.30	3.58	3.96	4.29	4.55	4.74	4.93	5.13	5.34	5.55	5.78	6.01	6.25	6.51	6.77	7.05	7.33	7.63	7.94	8.26	8.59	8.94	9.30	9.68	10.07	370.93	10.48	360.45		3	3
				e	e					4.14	4.35	4.70	5.09	5.50	5.91	6.50	7.01	7.43	7.73	8.04	8.36	8.70	9.06	9.42	9.80	10.20	10.61	11.04	11.49	11.96	12.44	12.94	13.47	14.01	14.58	15.17	15.79	16.43		17.09		17.78		
4	4	AEP	Yes	No	Yes	9.0%	33.2%	0.00	(84.48)	3.17	3.35	3.60	3.87	4.16	4.45	4.85	5.21	5.51	5.73	5.96	6.21	6.46	6.72	6.99	7.27	7.57	7.88	8.19	8.53	8.87	9.23	9.61	9.99	10.40	10.82	11.26	11.71	12.19	376.51	12.68	363.82		4	4
				e	e					5.09	5.35	5.80	6.28	6.80	7.32	8.03	8.64	9.15	9.52	9.91	10.31	10.73	11.16	11.61	12.08	12.57	13.08	13.61	14.16	14.74	15.33	15.96	16.60	17.27	17.97	18.70	19.46	20.25		21.07		21.92		
5	6	Avista	Yes	Yes	Yes	9.5%	30.0%	0.00	(38.86)	1.76	1.84	1.94	2.04	2.15	2.26	2.43	2.59	2.73	2.84	2.96	3.08	3.20	3.33	3.47	3.61	3.75	3.90	4.06	4.23	4.40	4.58	4.76	4.95	5.15	5.36	5.58	5.81	6.04	177.87	6.29	171.58		6	5
				e	e					2.12	2.30	2.51	2.75	3.00	3.25	3.50	3.72	3.91	4.07	4.23	4.40	4.58	4.77	4.96	5.16	5.37	5.59	5.81	6.05	6.29	6.55	6.81	7.09	7.38	7.67	7.99	8.31	8.65		9.00		9.36		
6	7	Black Hills	Yes	No	Yes	9.2%	32.0%	0.00	(59.97)	2.41	2.53	2.70	2.88	3.07	3.26	3.54	3.80	4.01	4.17	4.34	4.51	4.70	4.89	5.08	5.29	5.51	5.73	5.96	6.20	6.45	6.71	6.99	7.27	7.56	7.87	8.19	8.52	8.86	266.69	9.22	257.46		7	6
				e	e					3.99	3.75	4.20	4.69	5.25	5.81	6.32	6.77	7.15	7.44	7.74	8.06	8.38	8.72	9.08	9.44	9.83	10.22	10.64	11.07	11.52	11.98	12.47	12.97	13.50	14.05	14.62	15.21	15.82		16.46		17.13		
7	8	CenterPoint	Yes	No	No	7.4%	49.7%	0.00	(29.66)	0.72	0.77	0.83	0.89	0.95	1.01	1.07	1.12	1.18	1.22	1.27	1.32	1.38	1.43	1.49	1.55	1.62	1.68	1.75	1.82	1.89	1.97	2.05	2.13	2.22	2.31	2.40	2.50	2.60	125.52	2.71	122.81		8	7
				e	e					1.50	1.65	1.74	1.84	1.95	2.06	2.26	2.45	2.59	2.70	2.81	2.92	3.04	3.16	3.29	3.42	3.56	3.71	3.86	4.01	4.18	4.34	4.52	4.70	4.89	5.09	5.30	5.51	5.74		5.97		6.21		
8	9	CMS	Yes	No	No	8.0%	42.3%	0.00	(60.03)	1.84	1.95	2.06	2.18	2.30	2.42	2.63	2.82	2.97	3.09	3.22	3.35	3.49	3.63	3.77	3.93	4.09	4.25	4.42	4.60	4.79	4.98	5.18	5.39	5.61	5.84	6.08	6.32	6.58	258.37	6.84	251.53		9	8
				e	e					2.84	3.05	3.27	3.50	3.75	4.00	4.37	4.70	4.97	5.17	5.38	5.60	5.82	6.06	6.30	6.56	6.83	7.10	7.39	7.69	8.00	8.32	8.66	9.01	9.38	9.76	10.15	10.56	10.99		11.44		11.90		
9	10	Consol Ed	No	Yes	Yes	8.2%	39.6%	0.00	(92.86)	3.16	3.24	3.43	3.64	3.86	4.08	4.37	4.64	4.88	5.07	5.28	5.49	5.72	5.95	6.19	6.44	6.70	6.97	7.25	7.55	7.85	8.17	8.50	8.85	9.21	9.58	9.97	10.37	10.79	394.76	11.23	383.53		10	9
				e	e					4.55	4.85	5.21	5.59	6.00	6.41	6.95	7.44	7.85	8.16	8.49	8.84	9.20	9.57	9.96	10.36	10.78	11.22	11.67	12.14	12.63	13.15	13.68	14.23	14.81	15.41	16.03	16.68	17.36		18.06		18.79		
10	11	Dominion	Yes	No	No	9.4%	26.4%	0.00	(52.56)	2.67	2.67	2.82	2.99	3.16	3.33	3.46	3.60	3.74	3.89	4.05	4.21	4.38	4.56	4.74	4.94	5.14	5.34	5.56	5.79	6.02	6.26	6.52	6.78	7.06	7.34	7.64	7.95	8.27	205.16	8.61	196.55		11	#
				e	e					4.12	4.00	4.31	4.64	5.00	5.36	5.76	6.12	6.43	6.69	6.96	7.25	7.54	7.85	8.16	8.49	8.84	9.20	9.57	9.96	10.36	10.78	11.21	11.67	12.14	12.63	13.14	13.68	14.23		14.81		15.41		
11	13	Duke	Yes	No	Yes	8.5%	36.2%	0.00	(91.96)	3.98	4.06	4.14	4.22	4.30	4.38	4.63	4.86	5.08	5.29	5.50	5.73	5.96	6.20	6.45	6.71	6.98	7.27	7.56	7.87	8.19	8.52	8.86	9.22	9.59	9.98	10.39	10.81	11.25	388.05	11.70	376.35		13	#
				e	e					5.33	5.65	6.07	6.52	7.00	7.48	8.09	8.64	9.11	9.48	9.86	10.26	10.67	11.11	11.56	12.02	12.51	13.02	13.55	14.09	14.66	15.26	15.88	16.52	17.19	17.89	18.61	19.36	20.15		20.96		21.81		
12	14	Edison Int'l	Yes	No	No	12.1%	49.3%	0.00	(70.98)	2.84	2.95	3.17	3.40	3.65	3.90	4.24	4.55	4.81	5.00	5.20	5.41	5.63	5.86	6.10	6.35	6.60	6.87	7.15	7.44	7.74	8.05	8.38	8.72	9.07	9.44	9.82	10.22	10.63	1,072.79	11.06	1,061.72		14	#
				e	e					1.61	4.70	5.22	5.80	6.45	7.10	8.28	9.30	10.05	10.46	10.89	11.33	11.78	12.26	12.76	13.28	13.81	14.37	14.95	15.56	16.19	16.85	17.53	18.24	18.98	19.75	20.55	21.38	22.24		23.14		24.08		
13	15	Entergy	Yes	No	No	8.5%	29.9%	0.00	(100.49)	4.10	4.30	4.52	4.75	5.00	5.25	5.66	6.03	6.35	6.60	6.87	7.15	7.44	7.74	8.06	8.38	8.72	9.07	9.44	9.82	10.22	10.64	11.07	11.51	11.98	12.47	12.97	13.50	14.04	350.43	14.61	335.82		15	#
				e	e					5.39	5.85	6.06	6.28	6.50	6.72	6.97	7.24	7.52	7.83	8.14	8.47	8.81	9.17	9.54	9.93	10.33	10.75	11.19	11.64	12.11	12.60	13.11	13.64	14.19	14.77	15.37	15.99	16.64		17.31		18.01		
14	16	Evergy	Yes	Yes	Yes	9.5%	33.5%	0.00	(59.37)	2.33	2.53	2.69	2.87	3.05	3.23	3.54	3.80	4.02	4.19	4.35	4.53	4.71	4.91	5.10	5.31	5.53	5.75	5.98	6.23	6.48	6.74	7.01	7.30	7.59	7.90	8.22	8.55	8.90	299.47	9.26	290.21		16	#
				e	e					3.26	3.65	4.01	4.41	4.85	5.29	5.82	6.28	6.65	6.92	7.20	7.50	7.80	8.11	8.44	8.79	9.14	9.51	9.90	10.30	10.71	11.15	11.60	12.07	12.56	13.07	13.60	14.15	14.72		15.32		15.94		
15	17	Eversource	No	Yes	Yes	9.1%	33.5%	0.00	(71.02)	2.55	2.70	2.94	3.20	3.48	3.76	4.13	4.45	4.71	4.91	5.10	5.31	5.53	5.75	5.98	6.22	6.48	6.74	7.01	7.30	7.59	7.90	8.22	8.55	8.90	9.26	9.63	10.02	10.43	326.34	10.85	315.48		17	#
				e	e					4.09	4.35	4.73	5.15	5.60	6.05	6.64	7.16	7.59	7.89	8.21	8.55	8.89	9.25	9.63	10.02	10.42	10.84	11.28	11.74	12.22	12.71	13.23	13.76	14.32	14.90	15.50	16.13	16.78		17.46		18.17		
16	18	Exelon	Yes	No	No	8.2%	37.1%	0.00	(41.37)	1.35	1.44	1.55	1.67	1.80	1.93	2.05	2.17	2.27	2.37	2.46	2.56	2.66	2.77	2.88	3.00	3.12	3.25	3.38	3.52	3.66	3.81	3.96	4.12	4.29	4.46	4.64	4.83	5.03	162.88	5.23	157.65		18	#
				e	e					2.26	2.40	2.59	2.78	3.00	3.22	3.33	3.46	3.60	3.74	3.89	4.05	4.21	4.39	4.56	4.75	4.94	5.14	5.35	5.57	5.79	6.03	6.27	6.52	6.79	7.06	7.35	7.65	7.96		8.28		8.61		
17	22	IDACORP	Yes	Yes	Yes	8.1%	38.0%	0.00	(102.43)	3.04	3.20	3.49	3.81	4.15	4.49	4.93	5.31	5.63	5.85	6.09	6.34	6.60	6.86	7.14	7.43	7.73	8.04	8.37	8.71	9.06	9.43	9.81	10.21	10.62	11.05	11.50	11.96	12.45	404.24	12.95	391.28		22	#
				e	e					5.11	5.10	5.47	5.87	6.30	6.73	7.26	7.74	8.15	8.48	8.82	9.18	9.55	9.94	10.34	10.76	11.20	11.65	12.12	12.61	13.12	13.66	14.21	14.78	15.38	16.01	16.65	17.33	18.03		18.76		19.52		
18	23	MGE	Yes	No	No	6.3%	56.3%	0.00	(79.73)	1.59	1.66	1.74	1.82	1.90	1.98	2.14	2.27	2.39	2.49	2.59	2.69	2.80	2.92	3.04	3.16	3.29	3.42	3.56	3.70	3.85	4.01	4.17	4.34	4.51	4.70	4.89	5.09	5.29	283.14	5.51	277.63		23	#
				e	e					3.00	3.15	3.26	3.38	3.50	3.62	3.90	4.15	4.36	4.54	4.72	4.91	5.11	5.32	5.53	5.76	5.99	6.23	6.49	6.75	7.02	7.31	7.60	7.91	8.23	8.57	8.91	9.27	9.65		10.04		10.45		
19	24	NextEra	Yes	No	No	8.8%	44.0%	0.00	(73.14)	1.70	1.87	2.12	2.41	2.74	3.07	3.47	3.82	4.09	4.26	4.43	4.61	4.79	4.99	5.19	5.40	5.62	5.85	6.08	6.33	6.59	6.85	7.13	7.42	7.72	8.03	8.36	8.70	9.05	398.86	9.41	389.45		24	#
				e	e					2.91	3.15	3.52	3.94	4.40	4.86	5.50	6.05	6.47	6.73	7.00	7.29	7.58	7.89	8.21	8.54	8.89	9.25	9.62	10.01	10.42	10.84	11.28	11.74	12.21	12.71	13.22	13.76	14.31		14.89		15.50		
20	25	NorthWester	Yes	Yes	Yes	8.6%	33.2%	0.00	(56.39)	2.52	2.56	2.63	2.69	2.76	2.83	3.00	3.15	3.30	3.44	3.57	3.72	3.87	4.03	4.19	4.36	4.54	4.72	4.91	5.11	5.32	5.53	5.76	5.99	6.23	6.48	6.75	7.02	7.30	221.12	7.60	213.52		25	#
				e	e					3.29	3.45	3.67	3.90	4.15	4.40	4.69	4.96	5.20	5.41	5.63	5.86	6.10	6.34	6.60	6.87	7.15	7.43	7.74	8.05	8.37	8.71	9.07	9.43	9.82	10.21	10.63	11.06	11.51		11.97		12.46		
21	26	OGE	Yes	Yes	Yes	9.2%	34.3%	0.00	(36.08)	1.64	1.66	1.72	1.78	1.85	1.92	2.04	2.15	2.25	2.34	2.44	2.54	2.64	2.75	2.86	2.98	3.10	3.22	3.35	3.49	3.63	3.78	3.93	4.09	4.25	4.43	4.61	4.79	4.99	174.70	5.19	169.52		26	#
				e	e					2.25	2.00	2.33	2.71	3.15	3.59	3.90	4.18	4.41	4.59	4.78	4.97	5.17	5.38	5.60	5.83	6.06	6.31	6.56	6.83	7.11	7.40	7.69	8.01	8.33	8.67	9.02	9.38	9.76		10.16		10.57		
22	27	Otter Tail	Yes	No	Yes	4.7%	37.2%	0.00	(83.21)	1.65	1.76	1.90	2.04	2.20	2.36	2.58	2.77	2.93	3.05	3.17	3.30	3.44	3.58	3.72	3.87	4.03	4.19	4.36	4.54	4.72	4.91	5.11	5.32	5.54	5.76	5.99	6.24	6.49	122.37	6.75	115.62		27	#
				e	e					6.78	4.80	4.38	4.00	3.65	3.30	3.53	3.74	3.93	4.09	4.26	4.43	4.61	4.80	4.99	5.19	5.40	5.62	5.85	6.09	6.33	6.59	6.86	7.13	7.42	7.72	8.04	8.36	8.70		9.05		9.42		
23	30	Pinnacle	Yes	Yes	Yes	8.5%	36.8%	0.00	(82.28)	3.42	3.48	3.57	3.66	3.75	3.84	4.08	4.31	4.51	4.70	4.89	5.08	5.29	5.50	5.73	5.96	6.20	6.45	6.71	6.99	7.27	7.56	7.87	8.19	8.52	8.86	9.22	9.60	9.99	346.63	10.39	336.24		30	#
				e	e					4.27	4.15	4.61	5.13	5.70	6.27	6.63	6.97	7.29	7.58	7.89	8.21	8.54	8.88	9.24	9.62	10.01	10.41	10.84	11.27	11.73	12.21	12.70	13.21	13.75	14.31	14.89	15.49	16.12		16.77		17.45		
24	33	Public Serv.	Yes	No	No	8.5%	36.0%	0.00	(62.96)	2.16	2.28	2.44	2.61	2.80	2.99	3.25	3.48	3.68	3.83	3.98	4.14	4.31	4.48	4.67	4.85	5.05	5.26	5.47	5.69	5.92	6.16	6.41	6.67	6.94	7.22	7.51	7.82	8.13	261.83	8.46	253.36		33	#
				e	e					3.47	3.55	3.84	4.16	4.50	4.84	5.21	5.54	5.83	6.07	6.31	6.57	6.83	7.11	7.40	7.70	8.01	8.33	8.67	9.02	9.39	9.77	10.16	10.58	11.00	11.45	11.91	12.40	12.90		13.42		13.96		
25	34	Sempra	Yes	Yes	Yes	8.4%	39.3%	0.00	(147.16)	4.58	4.76	5.17	5.62	6.10	6.58	7.20	7.75	8.20	8.53	8.88	9.24	9.61	10.00	10.41	10.83	11.27	11.72	12.20	12.69	13.21	13.74	14.30	14.88	15.48	16.10	16.76	17.44	18.14	659.61	18.88	640.73		34	#
				e	e					9.21	9.00	9.91	10.90	12.00	13.10	14.52	15.76	16.74	17.42	18.13	18.86	19.62	20.42	21.25	22.11	23.00	23.93	24.90	25.91	26.96	28.05	29.19	30.37	31.60	32.88	34.21	35.60	37.04		38.54		40.10		
26	35	Southern	Yes	No	No	8.7%	40.5%	0.00	(71.19)	2.70	2.78	2.88	2.99	3.10	3.21	3.42	3.62	3.80	3.96	4.12	4.28	4.46	4.64	4.82	5.02	5.22	5.43	5.65	5.88	6.12	6.37	6.63	6.90	7.17	7.47	7.77	8.08	8.41	348.72	8.75	339.97		35	#
				e	e					3.61	3.65	4.09	4.59	5.15	5.71	6.28	6.79	7.20	7.49	7.79	8.11	8.44	8.78	9.13	9.50	9.89	10.29	10.71	11.14	11.59	12.06	12.55	13.06	13.59	14.14	14.71	15.30	15.92		16.57		17.24		
27	36	WEC	Yes	Yes	Yes	8.5%	38.3%	0.00	(89.21)	2.91	3.12	3.33	3.56	3.80	4.04	4.42	4.76	5.04	5.24	5.46	5.68	5.91	6.15	6.39	6.65	6.92	7.20	7.49	7.80	8.11	8.44	8.78	9.14	9.51	9.90	10.30	10.71	11.15	394.64	11.60	383.04		36	#
				e	e					4.46	4.60	5.00	5.43	5.90	6.37	7.00	7.55	8.00	8.32	8.66	9.01	9.37	9.75	10.15	10.56	10.98	11.43	11.89	12.37	12.88	13.40	13.94	14.50	15.09	15.70	16.34	17.00	17.69		18.41		19.15		
28	37	Xcel	Yes	No	Yes	8.5%	38.1%	0.00	(62.59)	1.95	2.08	2.26	2.45	2.66	2.87	3.16	3.41	3.62	3.76	3.92	4.07	4.24	4.41	4.59	4.78	4.97	5.17	5.38	5.60	5.82	6.06	6.30	6.56	6.83	7.10	7.39	7.69	8.00	278.96	8.32	270.64		37	#
				e	e					3.17	3.35	3.63	3.93	4.25	4.57	5.02	5.40	5.72	5.95	6.20	6.45	6.71	6.98	7.26	7.56	7.86	8.18	8.51	8.86	9.22	9.59	9.98	10.38	10.80	11.24	11.69	12.17	12.66		13.17		13.71		
		No. of Peers:	26	12	17																																							

Mean			
8.56%	37.86%	0.00%	Company Screen
8.72%	36.29%	0.00%	Staff Screen
8.51%	36.00%	0.00%	Staff Sensitivity Screen

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		
	#	Abbreviated Utility	PGE Peers	Staff Peers	LT Debt Staff Sensitivity	IRR	Terminal Value as % of NPV$_{DIV}$	NPV @ IRR	Recent Price*	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2046 Terminal Value	2049 Div	2049 Sale	2050	#	
										Initial Stage					Transition Stage					Final Stage																								
1	1	Allete	Yes	No	No	9.5%	32.5%	0.00	(57.67)	2.71	2.80	2.90	3.00	3.10	3.31	3.50	3.67	3.82	3.98	4.14	4.31	4.48	4.66	4.85	5.05	5.25	5.47	5.69	5.92	6.16	6.41	6.67	6.94	7.22	7.51	7.81	8.13	8.46	286.76	8.80	277.95		1	1
				e	e					3.40	3.70	4.09	4.52	5.00	5.48	6.00	6.46	6.84	7.12	7.41	7.71	8.02	8.34	8.68	9.03	9.40	9.78	10.18	10.59	11.02	11.46	11.93	12.41	12.91	13.44	13.98	14.55	15.14		15.75		16.39		
2	2	Alliant	Yes	Yes	Yes	8.9%	36.4%	0.00	(52.66)	1.81	1.96	2.12	2.29	2.46	2.70	2.91	3.08	3.20	3.33	3.46	3.60	3.75	3.90	4.06	4.22	4.40	4.57	4.76	4.95	5.15	5.36	5.58	5.80	6.04	6.28	6.54	6.80	7.08	247.76	7.37	240.39		2	2
				e	e					2.73	2.85	3.14	3.45	3.80	4.15	4.55	4.91	5.20	5.41	5.63	5.86	6.10	6.35	6.60	6.87	7.15	7.44	7.74	8.05	8.38	8.72	9.07	9.44	9.82	10.22	10.63	11.06	11.51		11.98		12.46		
3	3	Ameren	Yes	Yes	Yes	8.5%	38.5%	0.00	(83.91)	2.52	2.76	3.02	3.30	3.58	3.96	4.29	4.55	4.74	4.93	5.13	5.34	5.55	5.78	6.01	6.25	6.51	6.77	7.05	7.33	7.63	7.94	8.26	8.59	8.94	9.30	9.68	10.07	10.48	371.36	10.90	360.45		3	3
				e	e					4.14	4.35	4.70	5.09	5.50	5.91	6.50	7.01	7.43	7.73	8.04	8.36	8.70	9.06	9.42	9.80	10.20	10.61	11.04	11.49	11.96	12.44	12.94	13.47	14.01	14.58	15.17	15.79	16.43		17.09		17.78		
4	4	AEP	Yes	No	Yes	9.3%	31.4%	0.00	(84.48)	3.35	3.60	3.87	4.16	4.45	4.85	5.21	5.51	5.73	5.96	6.21	6.46	6.72	6.99	7.27	7.57	7.88	8.19	8.53	8.87	9.23	9.61	9.99	10.40	10.82	11.26	11.71	12.19	12.68	377.02	13.20	363.82		4	4
				e	e					5.09	5.35	5.80	6.28	6.80	7.32	8.03	8.64	9.15	9.52	9.91	10.31	10.73	11.16	11.61	12.08	12.57	13.08	13.61	14.16	14.74	15.33	15.96	16.60	17.27	17.97	18.70	19.46	20.25		21.07		21.92		
5	6	Avista	Yes	Yes	Yes	9.7%	28.4%	0.00	(38.86)	1.84	1.94	2.04	2.15	2.26	2.43	2.59	2.73	2.84	2.96	3.08	3.20	3.33	3.47	3.61	3.75	3.90	4.06	4.23	4.40	4.58	4.76	4.95	5.15	5.36	5.58	5.81	6.04	6.29	178.12	6.54	171.58		6	5
				e	e					2.12	2.30	2.51	2.75	3.00	3.25	3.50	3.72	3.91	4.07	4.23	4.40	4.58	4.77	4.96	5.16	5.37	5.59	5.81	6.05	6.29	6.55	6.81	7.09	7.38	7.67	7.99	8.31	8.65		9.00		9.36		
6	7	Black Hills	Yes	No	Yes	9.4%	30.2%	0.00	(59.97)	2.53	2.70	2.88	3.07	3.26	3.54	3.80	4.01	4.17	4.34	4.51	4.70	4.89	5.08	5.29	5.51	5.73	5.96	6.20	6.45	6.71	6.99	7.27	7.56	7.87	8.19	8.52	8.86	9.22	267.06	9.60	257.46		7	6
				e	e					3.99	3.75	4.20	4.69	5.25	5.81	6.32	6.77	7.15	7.44	7.74	8.06	8.38	8.72	9.08	9.44	9.83	10.22	10.64	11.07	11.52	11.98	12.47	12.97	13.50	14.05	14.62	15.21	15.82		16.46		17.13		
7	8	CenterPoint	Yes	No	No	7.5%	48.0%	0.00	(29.66)	0.77	0.83	0.89	0.95	1.01	1.07	1.12	1.18	1.22	1.27	1.32	1.38	1.43	1.49	1.55	1.62	1.68	1.75	1.82	1.89	1.97	2.05	2.13	2.22	2.31	2.40	2.50	2.60	2.71	125.62	2.82	122.81		8	7
				e	e					1.50	1.65	1.74	1.84	1.95	2.06	2.26	2.45	2.59	2.70	2.81	2.92	3.04	3.16	3.29	3.42	3.56	3.71	3.86	4.01	4.18	4.34	4.52	4.70	4.89	5.09	5.30	5.51	5.74		5.97		6.21		
8	9	CMS	Yes	No	No	8.2%	40.5%	0.00	(60.03)	1.95	2.06	2.18	2.30	2.42	2.63	2.82	2.97	3.09	3.22	3.35	3.49	3.63	3.77	3.93	4.09	4.25	4.42	4.60	4.79	4.98	5.18	5.39	5.61	5.84	6.08	6.32	6.58	6.84	258.65	7.12	251.53		9	8
										2.84	3.05	3.27	3.50	3.75	4.00	4.37	4.70	4.97	5.17	5.38	5.60	5.82	6.06	6.30	6.56	6.83	7.10	7.39	7.69	8.00	8.32	8.66	9.01	9.38	9.76	10.15	10.56	10.99		11.44		11.90		
9	10	Consol Ed	No	Yes	Yes	8.4%	38.0%	0.00	(92.86)	3.24	3.43	3.64	3.86	4.08	4.37	4.64	4.88	5.07	5.28	5.49	5.72	5.95	6.19	6.44	6.70	6.97	7.25	7.55	7.85	8.17	8.50	8.85	9.21	9.58	9.97	10.37	10.79	11.23	395.21	11.68	383.53		10	9
				e	e					4.55	4.85	5.21	5.59	6.00	6.41	6.95	7.44	7.85	8.16	8.49	8.84	9.20	9.57	9.96	10.36	10.78	11.22	11.67	12.14	12.63	13.15	13.68	14.23	14.81	15.41	16.03	16.68	17.36		18.06		18.79		
10	11	Dominion	Yes	No	No	9.6%	25.0%	0.00	(52.56)	2.67	2.82	2.99	3.16	3.33	3.46	3.60	3.74	3.89	4.05	4.21	4.38	4.56	4.74	4.94	5.14	5.34	5.56	5.79	6.02	6.26	6.52	6.78	7.06	7.34	7.64	7.95	8.27	8.61	205.50	8.95	196.55		11	#
				e	e					4.12	4.00	4.31	4.64	5.00	5.36	5.76	6.12	6.43	6.69	6.96	7.25	7.54	7.85	8.16	8.49	8.84	9.20	9.57	9.96	10.36	10.78	11.21	11.67	12.14	12.63	13.14	13.68	14.23		14.81		15.41		
11	13	Duke	Yes	No	Yes	8.7%	34.9%	0.00	(91.96)	4.06	4.14	4.22	4.30	4.38	4.63	4.86	5.08	5.29	5.50	5.73	5.96	6.20	6.45	6.71	6.98	7.27	7.56	7.87	8.19	8.52	8.86	9.22	9.59	9.98	10.39	10.81	11.25	11.70	388.52	12.18	376.35		13	#
				e	e					5.33	5.65	6.07	6.52	7.00	7.48	8.09	8.64	9.11	9.48	9.86	10.26	10.67	11.11	11.56	12.02	12.51	13.02	13.55	14.09	14.66	15.26	15.88	16.52	17.19	17.89	18.61	19.36	20.15		20.96		21.81		
12	14	Edison Int'l	Yes	No	No	12.2%	47.3%	######	(70.98)	2.95	3.17	3.40	3.65	3.90	4.24	4.55	4.81	5.00	5.20	5.41	5.63	5.86	6.10	6.35	6.60	6.87	7.15	7.44	7.74	8.05	8.38	8.72	9.07	9.44	9.82	10.22	10.63	11.06	1,073.23	11.51	1,061.72		14	#
				e	e					1.61	4.70	5.22	5.80	6.45	7.10	8.28	9.30	10.05	10.46	10.89	11.33	11.78	12.26	12.76	13.28	13.81	14.37	14.95	15.56	16.19	16.85	17.53	18.24	18.98	19.75	20.55	21.38	22.24		23.14		24.08		
13	15	Entergy	Yes	No	No	8.7%	28.3%	0.00	(100.49)	4.30	4.52	4.75	5.00	5.25	5.66	6.03	6.35	6.60	6.87	7.15	7.44	7.74	8.06	8.38	8.72	9.07	9.44	9.82	10.22	10.64	11.07	11.51	11.98	12.47	12.97	13.50	14.04	14.61	351.02	15.20	335.82		15	#
										5.39	5.85	6.06	6.28	6.50	6.72	6.97	7.24	7.52	7.83	8.14	8.47	8.81	9.17	9.54	9.93	10.33	10.75	11.19	11.64	12.11	12.60	13.11	13.64	14.19	14.77	15.37	15.99	16.64		17.31		18.01		
14	16	Evergy	Yes	Yes	Yes	9.7%	31.6%	0.00	(59.37)	2.53	2.69	2.87	3.05	3.23	3.54	3.80	4.02	4.19	4.35	4.53	4.71	4.91	5.10	5.31	5.53	5.75	5.98	6.23	6.48	6.74	7.01	7.30	7.59	7.90	8.22	8.55	8.90	9.26	299.85	9.63	290.21		16	#
				e	e					3.26	3.65	4.01	4.41	4.85	5.29	5.82	6.28	6.65	6.92	7.20	7.50	7.80	8.11	8.44	8.79	9.14	9.51	9.90	10.30	10.71	11.15	11.60	12.07	12.56	13.07	13.60	14.15	14.72		15.32		15.94		
15	17	Eversource	No	Yes	Yes	9.3%	31.5%	0.00	(71.02)	2.70	2.94	3.20	3.48	3.76	4.13	4.45	4.71	4.91	5.10	5.31	5.53	5.75	5.98	6.22	6.48	6.74	7.01	7.30	7.59	7.90	8.22	8.55	8.90	9.26	9.63	10.02	10.43	10.85	326.77	11.29	315.48		17	#
				e	e					4.09	4.35	4.73	5.15	5.60	6.05	6.64	7.16	7.59	7.89	8.21	8.55	8.89	9.25	9.63	10.02	10.42	10.84	11.28	11.74	12.22	12.71	13.23	13.76	14.32	14.90	15.50	16.13	16.78		17.46		18.17		
16	18	Exelon	Yes	No	No	8.4%	35.3%	0.00	(41.37)	1.44	1.55	1.67	1.80	1.93	2.05	2.17	2.27	2.37	2.46	2.56	2.66	2.77	2.88	3.00	3.12	3.25	3.38	3.52	3.66	3.81	3.96	4.12	4.29	4.46	4.64	4.83	5.03	5.23	163.09	5.44	157.65		18	#
				e	e					2.26	2.40	2.59	2.78	3.00	3.22	3.33	3.46	3.60	3.74	3.89	4.05	4.21	4.39	4.56	4.75	4.94	5.14	5.35	5.57	5.79	6.03	6.27	6.52	6.79	7.06	7.35	7.65	7.96		8.28		8.61		
17	22	IDACORP	Yes	Yes	Yes	8.3%	36.1%	0.00	(102.43)	3.20	3.49	3.81	4.15	4.49	4.93	5.31	5.63	5.85	6.09	6.34	6.60	6.86	7.14	7.43	7.73	8.04	8.37	8.71	9.06	9.43	9.81	10.21	10.62	11.05	11.50	11.96	12.45	12.95	404.76	13.48	391.28		22	#
				e	e					5.11	5.10	5.47	5.87	6.30	6.73	7.26	7.74	8.15	8.48	8.82	9.18	9.55	9.94	10.34	10.76	11.20	11.65	12.12	12.61	13.12	13.66	14.21	14.78	15.38	16.01	16.65	17.33	18.03		18.76		19.52		
18	23	MGE	Yes	No	No	6.4%	54.9%	0.00	(79.73)	1.66	1.74	1.82	1.90	1.98	2.14	2.27	2.39	2.49	2.59	2.69	2.80	2.92	3.04	3.16	3.29	3.42	3.56	3.70	3.85	4.01	4.17	4.34	4.51	4.70	4.89	5.09	5.29	5.51	283.36	5.73	277.63		23	#
										3.00	3.15	3.26	3.38	3.50	3.62	3.90	4.15	4.36	4.54	4.72	4.91	5.11	5.32	5.53	5.76	5.99	6.23	6.49	6.75	7.02	7.31	7.60	7.91	8.23	8.57	8.91	9.27	9.65		10.04		10.45		
19	24	NextEra	Yes	No	No	9.0%	41.7%	0.00	(73.14)	1.87	2.12	2.41	2.74	3.07	3.47	3.82	4.09	4.26	4.43	4.61	4.79	4.99	5.19	5.40	5.62	5.85	6.08	6.33	6.59	6.85	7.13	7.42	7.72	8.03	8.36	8.70	9.05	9.41	399.24	9.80	389.45		24	#
				e	e					2.91	3.15	3.52	3.94	4.40	4.86	5.50	6.05	6.47	6.73	7.00	7.29	7.58	7.89	8.21	8.54	8.89	9.25	9.62	10.01	10.42	10.84	11.28	11.74	12.21	12.71	13.22	13.76	14.31		14.89		15.50		
20	25	NorthWester	Yes	Yes	Yes	8.7%	31.9%	0.00	(56.39)	2.56	2.63	2.69	2.76	2.83	3.00	3.15	3.30	3.44	3.57	3.72	3.87	4.03	4.19	4.36	4.54	4.72	4.91	5.11	5.32	5.53	5.76	5.99	6.23	6.48	6.75	7.02	7.30	7.60	221.43	7.91	213.52		25	#
				e	e					3.29	3.45	3.67	3.90	4.15	4.40	4.69	4.96	5.20	5.41	5.63	5.86	6.10	6.34	6.60	6.87	7.15	7.43	7.74	8.05	8.37	8.71	9.07	9.43	9.82	10.21	10.63	11.06	11.51		11.97		12.46		
21	26	OGE	Yes	Yes	Yes	9.4%	32.9%	0.00	(36.08)	1.66	1.72	1.78	1.85	1.92	2.04	2.15	2.25	2.34	2.44	2.54	2.64	2.75	2.86	2.98	3.10	3.22	3.35	3.49	3.63	3.78	3.93	4.09	4.25	4.43	4.61	4.79	4.99	5.19	174.91	5.40	169.52		26	#
				e	e					2.25	2.00	2.33	2.71	3.15	3.59	3.90	4.18	4.41	4.59	4.78	4.97	5.17	5.38	5.60	5.83	6.06	6.31	6.56	6.83	7.11	7.40	7.69	8.01	8.33	8.67	9.02	9.38	9.76		10.16		10.57		
22	27	Otter Tail	Yes	No	Yes	4.8%	35.6%	0.00	(83.21)	1.76	1.90	2.04	2.20	2.36	2.58	2.77	2.93	3.05	3.17	3.30	3.44	3.58	3.72	3.87	4.03	4.19	4.36	4.54	4.72	4.91	5.11	5.32	5.54	5.76	5.99	6.24	6.49	6.75	122.64	7.02	115.62		27	#
				e	e					6.78	4.80	4.38	4.00	3.65	3.30	3.53	3.74	3.93	4.09	4.26	4.43	4.61	4.80	4.99	5.19	5.40	5.62	5.85	6.09	6.33	6.59	6.86	7.13	7.42	7.72	8.04	8.36	8.70		9.05		9.42		
23	30	Pinnacle	Yes	Yes	Yes	8.6%	35.4%	0.00	(82.28)	3.48	3.57	3.66	3.75	3.84	4.08	4.31	4.51	4.70	4.89	5.08	5.29	5.50	5.73	5.96	6.20	6.45	6.71	6.99	7.27	7.56	7.87	8.19	8.52	8.86	9.22	9.60	9.99	10.39	347.05	10.81	336.24		30	#
										4.27	4.15	4.61	5.13	5.70	6.27	6.63	6.97	7.29	7.58	7.89	8.21	8.54	8.88	9.24	9.62	10.01	10.41	10.84	11.27	11.73	12.21	12.70	13.21	13.75	14.31	14.89	15.49	16.12		16.77		17.45		
24	33	Public Serv.	Yes	No	No	8.7%	34.2%	0.00	(62.96)	2.28	2.44	2.61	2.80	2.99	3.25	3.48	3.68	3.83	3.98	4.14	4.31	4.48	4.67	4.85	5.05	5.26	5.47	5.69	5.92	6.16	6.41	6.67	6.94	7.22	7.51	7.82	8.13	8.46	262.17	8.81	253.36		33	#
				e	e					3.47	3.55	3.84	4.16	4.50	4.84	5.21	5.54	5.83	6.07	6.31	6.57	6.83	7.11	7.40	7.70	8.01	8.33	8.67	9.02	9.39	9.77	10.16	10.58	11.00	11.45	11.91	12.40	12.90		13.42		13.96		
25	34	Sempra	Yes	Yes	Yes	8.6%	37.5%	0.00	(147.16)	4.76	5.17	5.62	6.10	6.58	7.20	7.75	8.20	8.53	8.88	9.24	9.61	10.00	10.41	10.83	11.27	11.72	12.20	12.69	13.21	13.74	14.30	14.88	15.48	16.10	16.76	17.44	18.14	18.88	660.37	19.64	640.73		34	#
				e	e					9.21	9.00	9.91	10.90	12.00	13.10	14.52	15.76	16.74	17.42	18.13	18.86	19.62	20.42	21.25	22.11	23.00	23.93	24.90	25.91	26.96	28.05	29.19	30.37	31.60	32.88	34.21	35.60	37.04		38.54		40.10		
26	35	Southern	Yes	No	No	8.8%	39.0%	0.00	(71.19)	2.78	2.88	2.99	3.10	3.21	3.42	3.62	3.80	3.96	4.12	4.28	4.46	4.64	4.82	5.02	5.22	5.43	5.65	5.88	6.12	6.37	6.63	6.90	7.17	7.47	7.77	8.08	8.41	8.75	349.07	9.10	339.97		35	#
				e	e					3.61	3.65	4.09	4.59	5.15	5.71	6.28	6.79	7.20	7.49	7.79	8.11	8.44	8.78	9.13	9.50	9.89	10.29	10.71	11.14	11.59	12.06	12.55	13.06	13.59	14.14	14.71	15.30	15.92		16.57		17.24		
27	36	WEC	Yes	Yes	Yes	8.7%	36.5%	0.00	(89.21)	3.12	3.33	3.56	3.80	4.04	4.42	4.76	5.04	5.24	5.46	5.68	5.91	6.15	6.39	6.65	6.92	7.20	7.49	7.80	8.11	8.44	8.78	9.14	9.51	9.90	10.30	10.71	11.15	11.60	395.11	12.07	383.04		36	#
				e	e					4.46	4.60	5.00	5.43	5.90	6.37	7.00	7.55	8.00	8.32	8.66	9.01	9.37	9.75	10.15	10.56	10.98	11.43	11.89	12.37	12.88	13.40	13.94	14.50	15.09	15.70	16.34	17.00	17.69		18.41		19.15		
28	37	Xcel	Yes	No	Yes	8.7%	36.1%	0.00	(62.59)	2.08	2.26	2.45	2.66	2.87	3.16	3.41	3.62	3.76	3.92	4.07	4.24	4.41	4.59	4.78	4.97	5.17	5.38	5.60	5.82	6.06	6.30	6.56	6.83	7.10	7.39	7.69	8.00	8.32	279.30	8.66	270.64		37	#
				e	e					3.17	3.35	3.63	3.93	4.25	4.57	5.02	5.40	5.72	5.95	6.20	6.45	6.71	6.98	7.26	7.56	7.86	8.18	8.51	8.86	9.22	9.59	9.98	10.38	10.80	11.24	11.69	12.17	12.66		13.17		13.71		
		No. of Peers:	26	12	17																																							

Mean			
8.73%	36.16%	0.00%	Company Screen
8.90%	34.55%	0.00%	Staff Screen
8.69%	34.28%	0.00%	Staff Sensitivity Screen

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

Model Y **EPS Growth**

	1	2	3	4		5	6	7	8	9		
	Screen #	Abbreviated Utility	PGE Peers	Staff Peers	LT Debt Staff Sensitivity	Average IRR	Terminal Value as % of NPV_{DIV}	Average 2017 - 2021 Dividend Growth Rates EOY	BOY	Average	Screen #	
1	1	Allete	Yes	No	No	9.4%	#######	3.6%	3.4%	3.5%	1	1
2	2	Alliant	Yes	Yes	Yes	8.8%	#######	7.6%	8.0%	7.8%	2	2
3	3	Ameren	Yes	Yes	Yes	8.4%	#######	8.7%	9.2%	9.0%	3	3
4	4	AEP	Yes	No	Yes	9.1%	#######	7.0%	7.4%	7.2%	4	4
5	6	Avista	Yes	Yes	Yes	9.6%	#######	5.1%	5.3%	5.2%	6	5
6	7	Black Hills	Yes	No	Yes	9.3%	#######	10.7%	6.6%	8.6%	7	6
7	8	CenterPoint	Yes	No	No	7.5%	#######	7.2%	7.1%	7.2%	8	7
8	9	CMS	Yes	No	No	8.1%	#######	5.7%	5.6%	5.7%	9	8
9	10	Consol Ed	No	Yes	Yes	8.3%	#######	5.1%	5.9%	5.5%	10	9
10	11	Dominion	Yes	No	No	9.5%	#######	4.3%	5.7%	5.0%	11	10
11	13	Duke	Yes	No	Yes	8.6%	#######	2.0%	1.9%	1.9%	13	11
12	14	Edison Int'l	Yes	No	No	12.2%	#######	6.5%	7.2%	6.9%	14	12
13	15	Entergy	Yes	No	No	8.6%	#######	5.1%	5.0%	5.0%	15	13
14	16	Evergy	Yes	Yes	Yes	9.6%	#######	7.0%	7.1%	7.0%	16	14
15	17	Eversource	No	Yes	Yes	9.2%	#######	8.1%	41.5%	24.8%	17	15
16	18	Exelon	Yes	No	No	8.3%	#######	7.5%	1.9%	4.7%	18	16
17	22	IDACORP	Yes	Yes	Yes	8.2%	#######	8.1%	7.2%	7.7%	22	17
18	23	MGE	Yes	No	No	6.4%	#######	4.6%	5.1%	4.8%	23	18
19	24	NextEra	Yes	No	No	8.9%	#######	12.7%	6.3%	9.5%	24	19
20	25	NorthWester	Yes	Yes	Yes	8.7%	#######	2.3%	8.6%	5.5%	25	20
21	26	OGE	Yes	Yes	Yes	9.3%	#######	3.1%	4.8%	3.9%	26	21
22	27	Otter Tail	Yes	No	Yes	4.8%	#######	7.5%	10.4%	8.9%	27	22
23	30	Pinnacle	Yes	Yes	Yes	8.5%	#######	2.3%	8.2%	5.3%	30	23
24	33	Public Serv.	Yes	No	No	8.6%	#######	6.7%	7.3%	7.0%	33	24
25	34	Sempra	Yes	Yes	Yes	8.5%	#######	7.4%	5.4%	6.4%	34	25
26	35	Southern	Yes	No	No	8.7%	#######	3.5%	7.6%	5.5%	35	26
27	36	WEC	Yes	Yes	Yes	8.6%	#######	6.9%	8.9%	7.9%	36	27
28	37	Xcel	Yes	No	Yes	8.6%	#######	8.1%	8.4%	8.2%	37	28
		No. of Peers:	26	12	17	Mean						
						8.64%	37.01%	6.20%	Company Screen			
						8.81%	35.42%	5.98%	Staff Screen			
						8.60%	35.14%	6.29%	Staff Sensitivity Screen			

CASE: UE 416
WITNESS: MATT MULDOON

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STAFF EXHIBIT 2904

ROE – Three-Stage DCF:
Summary and Recommendation

August 22, 2023

UE 416 Staff ROE Summary

Stage 3 – Long-Term Annual Dividend and EPS Growth Rates						
Component	Real Rate	TIPS Inflation Forecast	20-Yr Nominal Rate	Weight	Weighted Rate	
Energy Information Administration (EIA)	2.20%	2.33%	4.58%	12.50%	0.57%	
Organization for Economic Co-operation and Development (OECD)	1.49%	2.33%	3.85%	12.50%	0.48%	
Social Security Administration (SSA)	2.00%	2.33%	4.38%	12.50%	0.55%	
Congressional Budget Office (CBO)	1.75%	2.33%	4.12%	12.50%	0.52%	
BEA Nominal Historical,1980 Q1 – 2022 Q4	2.64%	2.33%	5.03%	50.0%	2.52%	
Composite				100%	4.63%	**Composite**
Congressional Budget Office Long-Term 20-Year Budget Outlook			4.05%	100.0%	4.05%	**CBO**
BEA Nominal Historical,1980 Q1 – 2022 Q4	2.64%	2.33%	5.03%	100.0%	5.03%	**Near Historical**

Though shown below for comparison purposes, Staff disagrees with the Company's third Stage Growth Rate 3.90%

	Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity								
	X	CBO	4.05%	Composite	4.63%	Historical	5.03%	PGE	3.90%
1	Company Peer Screen	8.26%		8.76%		9.10%		8.14%	
2	Staff Peer Screen	8.35%		8.84%		9.17%		8.22%	
3	Staff Sensitivity Peer Screen	8.28%		8.77%		9.11%		8.16%	

Hamada →

Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity (Hamada Adjusted)									
X	CBO	4.05%	Composite	4.63%	Historical	5.03%	PGE	3.90%	
Company Peer Screen	7.91%		8.41%		8.75%		7.79%		1
Staff Peer Screen	8.19%		8.68%		9.01%		8.06%		2
Staff Sensitivity Peer Screen	8.07%		8.56%		8.90%		7.95%		3

	Model Y: 3 Stage DCF - Dividend Growth with Terminal Value as Sales based upon EPS Growth and Terminal Stock Sale								
	Y	CBO	4.05%	Composite	4.63%	Historical	5.03%	PGE	3.90%
1	Company Peer Screen	8.64%		9.09%		9.40%		8.53%	
2	Staff Peer Screen	8.81%		9.26%		9.57%		8.70%	
3	Staff Sensitivity Peer Screen	8.60%		9.04%		9.35%		8.48%	

Hamada →

Model Y: 3 Stage DCF - Dividend & EPS Growth with Terminal Value as Stock Sale (Hamada Adjusted)									
Y	CBO	4.05%	Composite	4.63%	Historical	5.03%	PGE	3.90%	
Company Peer Screen	8.29%		8.74%		9.05%		8.18%		1
Staff Peer Screen	8.65%		9.10%		9.41%		8.54%		2
Staff Sensitivity Peer Screen	8.39%		8.83%		9.14%		8.27%		3

Best Fit Range of Reasonable ROEs	9.01%	to	9.41%	ROE	
Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by :				12.5	bps
	9.13%	to	9.53%	ROE	
	Midpoint	9.3%	ROE	Testimony	
Staff Point ROE Recommendation:		9.4%			

CAPM and Single Stage DCF point to the upper range of Staff's Three Stage DCF Modeling Results

Note: Staff disagrees with a potential upper limit of 9.68% relying on an excessive GDP growth rate.
Pacificorp reaches back to 1929 to pull in years with higher growth rates than have been experiences since 1980.
Staff provides this illustration to show how excessive inputs can distort modeling results.

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ROE:
Capital Asset Pricing Model (CAPM)

August 22, 2023

Staff's CAPM Modeling Results

PGE	4.05%	Rf Rate as shown in Exhibit PGE/1000 PGE Staff Liddle - Villadsen/56 -- Top Current Table
Direct	11.51%	Mkt Return as shown in Exhibit PGE/1000 PGE Staff Liddle - Villadsen/61 -- Top Current Table
Testimony	7.46%	PGE Mkt Risk Premium (MRP)
Staff	4.045%	R_f July 27, 2023 30-Yr UST Yield /WSJ www.wsj.com/market-data/bonds
	9.75%	30-Year S&P 500 Proxy Market Return Geometric Return
	5.70%	Staff 30-Yr Mkt Risk Premium (MRP)
	4.004%	R_f July 27, 2023 10-Yr UST Yield /WSJ www.wsj.com/market-data/bonds
	10.41%	10-Year S&P 500 Proxy Market Return Geometric Return
	6.41%	Staff 10-Yr Mkt Risk Premium (MRP)

$R_{PGE} = R_f + \text{Beta}^*\text{MRP}$

	Screen #	Abbreviated Utility	UE 416 PGE	UE 416 Staff	LT Debt UE 416 Sensitivity	Ticker	VL Q3 2023 Beta	Staff MRP 30 Yr ROE w VL Beta CAPM	Staff MRP 10 Yr ROE w VL Beta CAPM	PGE MRP PGE/1000 ROE w VL Beta CAPM	Screen #	
1	1	Allete	Yes	No	No	ALE	0.90	9.18%	9.77%	10.76%	1	1
2	2	Alliant	Yes	Yes	Yes	LNT	0.85	8.89%	9.45%	10.39%	2	2
3	3	Ameren	Yes	Yes	Yes	AEE	0.85	8.89%	9.45%	10.39%	3	3
4	4	AEP	Yes	No	Yes	AEP	0.75	8.32%	8.81%	9.65%	4	4
5	6	Avista	Yes	Yes	Yes	AVA	0.90	9.18%	9.77%	10.76%	6	5
6	7	Black Hills	Yes	No	Yes	BKH	0.95	9.46%	10.09%	11.14%	7	6
7	8	CenterPoint	Yes	No	No	CNP	1.10	10.32%	11.05%	12.26%	8	7
8	9	CMS	Yes	No	No	CMS	0.80	8.61%	9.13%	10.02%	9	8
9	10	Consol Ed	No	Yes	Yes	ED	0.75	8.32%	8.81%	9.65%	10	9
10	11	Dominion	Yes	No	No	D	0.85	8.89%	9.45%	10.39%	11	10
11	13	Duke	Yes	No	Yes	DUK	0.85	8.89%	9.45%	10.39%	13	11
12	14	Edison Int'l	Yes	No	No	EIX	0.95	9.46%	10.09%	11.14%	14	12
13	15	Entergy	Yes	No	No	ETR	0.90	9.18%	9.77%	10.76%	15	13
14	16	Evergy	Yes	Yes	Yes	EVRG	0.90	9.18%	9.77%	10.76%	16	14
15	17	Eversource	No	Yes	Yes	ES	0.90	9.18%	9.77%	10.76%	17	15
16	18	Exelon	Yes	No	No	EXC	0.00	4.05%	4.00%	4.05%	18	16
17	22	IDACORP	Yes	Yes	Yes	IDA	0.80	8.61%	9.13%	10.02%	22	17
18	23	MGE	Yes	No	No	MGEE	0.75	8.32%	8.81%	9.65%	23	18
19	24	NextEra	Yes	No	No	NEE	0.95	9.46%	10.09%	11.14%	24	19
20	25	NorthWester	Yes	Yes	Yes	NWE	0.90	9.18%	9.77%	10.76%	25	20
21	26	OGE	Yes	Yes	Yes	OGE	1.00	9.75%	10.41%	11.51%	26	21
22	27	Otter Tail	Yes	No	Yes	OTTR	0.85	8.89%	9.45%	10.39%	27	22
23	30	Pinnacle	Yes	Yes	Yes	PNW	0.90	9.18%	9.77%	10.76%	30	23
24	33	Public Serv.	Yes	No	No	PEG	0.90	9.18%	9.77%	10.76%	33	24
25	34	Sempra	Yes	Yes	Yes	SRE	0.95	9.46%	10.09%	11.14%	34	25
26	35	Southern	Yes	No	No	SRE	0.95	9.46%	10.09%	11.14%	35	26
27	36	WEC	Yes	Yes	Yes	SO	0.90	9.18%	9.77%	10.76%	36	27
28	37	Xcel	Yes	No	Yes	WEC	0.80	8.61%	9.13%	10.02%	37	28
		No. of Peers:	26	12	17			VL Betas	VL Betas	VL Betas		
					Company Screen		Mean	8.9%	9.5%	10.4%	ROE	
					Staff Screen		Mean	9.1%	9.7%	10.6%	ROE	
					Staff Sensitivity Screen		Mean	9.0%	9.6%	10.5%	ROE	

Points to Upper Half of Staff's 3-Stage DCF Results

CASE: UE 416
WITNESS: MATT MULDOON

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STAFF EXHIBIT 2906

ROE:
Gordon Growth – Single Stage DCF

August 22, 2023

Staff's Representative Single Stage (Gordon Growth) Discounted Cash Flow (DCF) Model

Presumes the Peer Utility will pay its divident as a fixed multiple of growth into the future as it is now.

The results would be true only if the utility stock's dividends were to grow at a constant rate forever.

Value of Stock $(P_0) = D_1 / (k - g)$ Stock Price Now = Next Year's Dividend / (Required Stock Return - Growth in Dividends)

$k = (D_1 / P_0) + g$ Required Rate of Return on Utility Equity = (Next Year's VL Dividend / Recent Stock Price) - Perpetual Growth

This Model Implies: **Points toward Upper End of Staff's 3-Stage DCF Modeling Results**

	1		2	3	4	5	6	7	8	9	10	11 = 9 + 10	12
	Screen #	Abbreviated Utility	UE 416 PGE	UE 416 Staff	LT Debt UE 416 Sensitivity	Ticker	Recent Stock $ Price	Current Dividend Yield	Next VL Annual Dividend	Anticipated Dividend Yield	VL Dividend Growth	Investor Required ROE	Screen #
1	1	Allete	Yes	No	No	ALE	57.67	4.5%	2.71	4.7%	3.5%	8.2%	1
2	2	Alliant	Yes	Yes	Yes	LNT	52.66	3.2%	1.81	3.4%	7.1%	10.5%	2
3	3	Ameren	Yes	Yes	Yes	AEE	83.91	2.8%	2.52	3.0%	8.3%	11.3%	3
4	4	AEP	Yes	No	Yes	AEP	84.48	3.8%	3.35	4.0%	6.5%	10.5%	4
5	6	Avista	Yes	Yes	Yes	AVA	38.86	4.5%	1.84	4.7%	4.8%	9.6%	6
6	7	Black Hills	Yes	No	Yes	BKH	59.97	4.0%	2.53	4.2%	6.0%	10.2%	7
7	8	CenterPoint	Yes	No	No	CNP	29.66	2.4%	0.77	2.6%	1.9%	4.5%	8
8	9	CMS	Yes	No	No	CMS	60.03	3.1%	1.95	3.2%	5.9%	9.1%	9
9	10	Consol Ed	No	Yes	Yes	ED	92.86	3.4%	3.24	3.5%	4.1%	7.5%	10
10	11	Dominion	Yes	No	No	D	52.56	5.1%	2.67	5.1%	-0.3%	4.8%	11
11	13	Duke	Yes	No	Yes	DUK	91.96	4.3%	4.06	4.4%	2.0%	6.4%	13
12	14	Edison Int'l	Yes	No	No	EIX	70.98	4.0%	2.95	4.2%	6.2%	10.3%	14
13	15	Entergy	Yes	No	No	ETR	100.49	4.1%	4.30	4.3%	4.9%	9.2%	15
14	16	Evergy	Yes	Yes	Yes	EVRG	59.37	3.9%	2.53	4.3%	6.8%	11.1%	16
15	17	Eversource	No	Yes	Yes	ES	71.02	3.6%	2.70	3.8%	7.4%	11.2%	17
16	18	Exelon	Yes	No	No	EXC	41.37	3.3%	1.44	3.5%	3.0%	6.5%	18
17	22	IDACORP	Yes	Yes	Yes	IDA	102.43	3.0%	3.20	3.1%	7.3%	10.4%	22
18	23	MGE	Yes	No	No	MGEE	79.73	2.0%	1.66	2.1%	4.6%	6.7%	23
19	24	NextEra	Yes	No	No	NEE	73.14	2.3%	1.87	2.6%	11.9%	14.4%	24
20	25	NorthWesten	Yes	Yes	Yes	NWE	56.39	4.5%	2.56	4.5%	2.4%	6.9%	25
21	26	OGE	Yes	Yes	Yes	OGE	36.08	4.5%	1.66	4.6%	2.9%	7.5%	26
22	27	Otter Tail	Yes	No	Yes	OTTR	83.21	2.0%	1.76	2.1%	6.8%	8.9%	27
23	30	Pinnacle	Yes	Yes	Yes	PNW	82.28	4.2%	3.48	4.2%	2.8%	7.1%	30
24	33	Public Serv.	Yes	No	No	PEG	62.96	3.4%	2.28	3.6%	6.1%	9.7%	33
25	34	Sempra	Yes	Yes	Yes	SRE	147.16	3.1%	4.76	3.2%	6.9%	10.2%	34
26	35	Southern	Yes	No	No	SO	71.19	3.8%	2.78	3.9%	3.4%	7.3%	35
27	36	WEC	Yes	Yes	Yes	SO	71.19	3.8%	3.12	4.4%	7.0%	11.4%	36
28	37	Xcel	Yes	No	Yes	WEC	89.21	3.3%	2.08	2.3%	7.8%	10.1%	37
		No. of Peers:	26	12	17							Mean	
											Company Screen	9.0%	ROE
											Staff Screen	9.6%	ROE
											Staff Sensitivity Screen	9.5%	ROE

Points toward upper end of Staff's 3 Stage DCF Modeling results.

CASE: UE 416
WITNESS: MATT MULDOON

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STAFF EXHIBIT 2907

ROE: Financial News that Investors in Electric Utilities Are Seeing

August 22, 2023

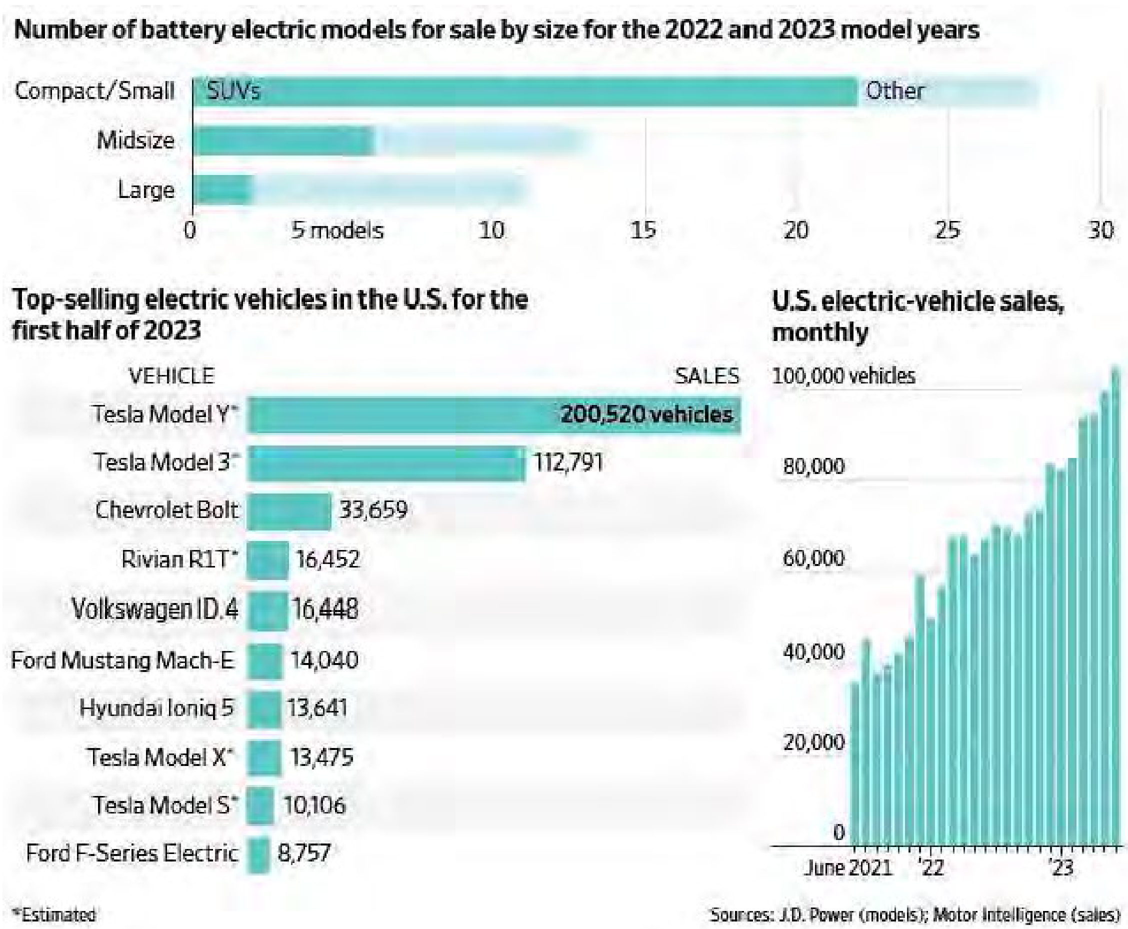
Financial News Investors Are Seeing

Automakers Plan Family-Size Electric SUVs

by Mike Colias – WSJ – Jul. 25, 2023

America's de facto family hauler – the **large, three-row SUV**—is finally **going electric**.

Car companies are planning to roll out **seven-seater electric SUVs**, with some, such as the **Kia EV9** and **Volvo EX90**, expected **in showrooms in coming months**. Today there are scant electric options in the large-SUV category, which has become the people mover of choice for U.S. families.



Auto executives say introducing larger plug-in SUVs will broaden the appeal of EV ownership to a new pool of buyers.

Many car shoppers – especially parents who shuttle children around town – have bypassed electrics because they haven't had the option for a larger vehicle with a third row of seating and more cargo space.

"For a lot of people, that third row is the No. 1 reason for purchase," says Jess Bala, director of global product planning at General Motors'

Cadillac brand, which is scheduled to reveal an **electric Escalade IQ large SUV** in **August**. "Those are often younger buyers who already are more interested in EVs."

Other car brands that have **confirmed large electric SUVs in** the **works** include **Hyundai** Motor, **Ford** Motor and **Toyota** Motor.

There was **just one large, seven-seat electric SUV on sale** in the **U.S.** for **model years 2022 and 2023**, according to research firm J.D. Power: **Mercedes-Benz's EQS**, priced at about **$105,000**. A few plug-in SUVs that J.D. Power categorizes as midsize also have a third row, including **Rivian's R1S** and **Tesla's Model X**.

Meanwhile, there were 22 small or compact electric SUVs for sale, the firm said. Many automakers targeted their earliest EV efforts at compact SUVs – the largest U.S. vehicle category – and pickup trucks, because they have traditionally been big moneymakers. Seven-seat SUVs are a logical next step because of their popularity, analysts say.

Through June, the top three EV sellers in the U.S. were Tesla's Model Y, a midsize SUV that offers a snug, optional third row; Tesla's Model 3, a compact sedan; and GM's Chevrolet Bolt, a small hatchback.

Buyers of those EVs tend to be early adopters – predominantly male – who are attracted by new technology. As automakers roll out bigger, family-oriented electrics, they have the chance to draw more female buyers, executives said.

For example, Kia expects women to account for about half the buyers of the EV9, a futuristic-looking three-row SUV set to go on sale in the fourth quarter. Kia's EV6 customer base – a midsize SUV that competes directly with a number of seven-seater electric SUVs, including the Kia EV9, are expected to land in showrooms in the coming months. Tesla's Model Y—is 75% men.

Big Electric SUVs Are Coming

"We're getting interest from people who have never thought about buying an EV, because they see that it still fits their lifestyle," said Kia's U.S. marketing chief, Russell Wager. "It's got the spaciousness and towing capability to get out of town, to take it camping."

Automakers, which are investing heavily to develop and produce new EV models, need to broaden interest in electrics as they roll out new entries. **EVs** account for roughly **7% of new-vehicle sales in** the **U.S.**

Larger offerings could help. **SUVs** that fit seven or eight people have surged in popularity over the past two decades, **largely displacing** the **minivan as** the **family car.** Some popular models include the Toyota Highlander, Ford Explorer and Chevrolet Tahoe.

Sales of midsize and large SUVs – most of which offer three rows of seating – have grown steadily, to 26% of U.S. vehicle sales this year through May, from 21% from the same period in 2018, according to data from Edmunds.

The pending influx of larger electric vehicles looms amid signs of some softness in the EV market.

EV leader Tesla and other carmakers have cut prices on popular electric models in recent months. While electric sales are growing faster than the broader car market, the pace of growth eased in the first half of the year.

The rollout of bigger SUVs also will represent a test of Americans' readiness to go electric with vehicles that are more likely to be used for road trips, where finding available charging stations can be a logistical challenge and lengthen travel times.

"I think there will be a lot of skepticism among consumers about how suitable a family EV will be for a road trip," said Ed Kim, president of automotive- research firm AutoPacific.

Many of the larger SUVs headed to market are expected to have driving ranges of at least 300 miles on a single charge. Kia's Wager said that is an important psychological number to help buyers get past range anxiety.

April Conyers is more concerned about the vehicle's size than its range, after having a baby late last year. She and her husband own a smaller Volvo EV, but things have gotten a little snug with the second- row car seat. They recently put down a deposit on a Volvo EX90, a three-row electric scheduled to go on sale next year.

"We've run into some practical space issues that we hadn't really thought about," said Conyers, a 41-year-old communications consultant. "The electric cars that are offered today aren't very big."

Auto executives say the interior space on the three-row EVs will be a selling point because in many cases they will be roomier than comparable gas-powered versions. That is partly because of the mechanical layout: No engine under the hood allows for a large front trunk, often called a frunk, which adds storage space.

"That extra cargo space we think is one of the biggest benefits these buyers will uncover," Cadillac's Bala said.

John Patterson, a car dealer with Hyundai, Kia and Mazda stores in South-ern California, said EV sales have been brisk, and he is eager to offer more choices.

"I think we're going to see a good amount of 28-to-45year-old women" coming in to buy the Kia EV9, he said.

The Volvo EX90 is a three-row electric vehicle that is scheduled to go on sale next year.

–

Bond Funds Stumbled During Fed's Rate Increases

by Matt Grossman – WSJ – Jul. 31, 2023

When it came to helping investors navigate recent debt-market turmoil induced by Federal Reserve rate increases, bond-picking fund managers largely came up short.

Of almost **2,000 actively managed bond funds** covering a range of investing strategies, **58% failed to beat comparable bond indexes after accounting for** the **fees** that investors pay over the past 18 months – roughly the stretch of the Fed's campaign – according to data from Morningstar Direct. With bond prices suffering across the board, **only** about **1 in 10** of the **funds posted positive returns**.

Most bond-index funds also lost money over that stretch. But many eked out a slightly better performance than active managers, in part because they cost less.

Passive index funds have posed stiff competition for active investing strategies for decades. Firms like **Vanguard** Group **and BlackRock** 's iShares unit have **popularized** the **idea** that **owning** a **broad basket of securities** is cheaper and no less lucrative than carefully curating a portfolio. But even some investors who have been sold on passive stock strategies still stand by active bond management, arguing that the quirks and complexities of debt investing mean their market is different.

Indeed, heading into 2022, active bond-fund managers had performed much better. An analysis by Fidelity Investments found that over the one-, three-, five- and 10-year periods through 2021, between 60% and 91% of active bond managers beat their benchmarks in strategies spanning short-term bonds, investment-grade funds and multisector approaches.

Then the **Fed** embarked on its most **aggressive rate-hiking campaign** since the 1980s. As interest rates rose from near-zero levels to more than 5%, the value of bonds outstanding plummeted in the worst year for debt markets in recent memory.

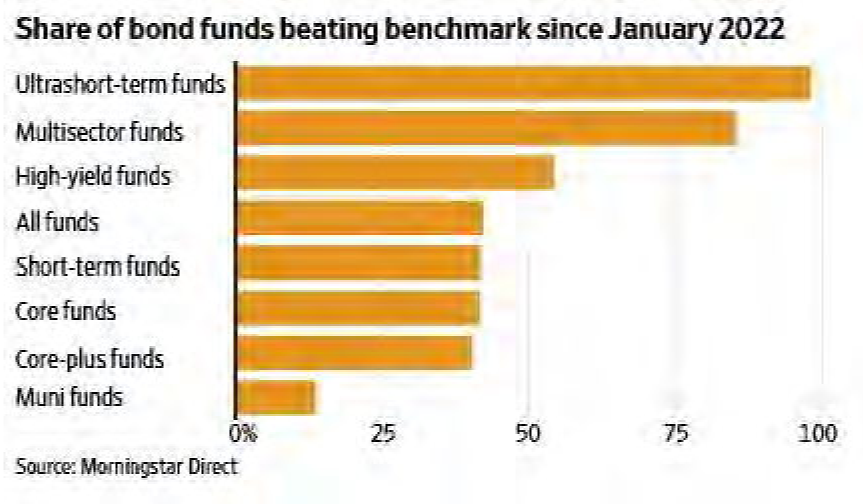
Periods of rapidly changing rates can be some of the most challenging conditions for bond managers, said Roger Aliaga-Diaz, head of portfolio construction at Vanguard, which offers both active and passive funds. "Of all the aspects of active management, forecasting interest rates is probably the most difficult," Aliaga-Diaz said.

Fixed-income managers' struggles spanned a broad range of bond categories. Only 14% of 102 intermediate-term municipal-bond funds beat Morningstar's benchmark. Of 169 funds that buy a blend of high-quality and junk-rated debt, 40% fared stronger than the index.

A majority of junk-focused managers eked out an above-benchmark showing, but 46% still lagged behind the benchmark.

Coming into 2022, fund teams found it challenging to guess how rapidly rates were about to climb, said George Truppi, a co-portfolio manager for Greenspring Funds' Income Opportunities Fund. As yields started to tick up, many were baited into pulling the trigger on buying medium-term bonds, only to watch values sink as persisting inflation fueled a further stream of Fed rate increases, he said. The **longer until** a **bond's maturity**, the **more its price falls when rates rise**.

Greenspring's fund, founded in late 2021, protected against that risk by choosing inexpensive bonds that Truppi's team believed would soon be paid off early by corporate borrowers. This year, for instance, the group made a quick profit when it correctly forecast that one borrower, road-salt maker Compass Minerals International, would repay its discounted junk-rated debt a year early.



Moves like that helped Greenspring effectively limit the fund's duration, a Wall Street measure of its sensitivity to changes in rates. The strategy helped the fund achieve a 2.7% return between January 2022 and June 2023, one of the best results of the junk-bond funds Morningstar tracked.

Other top-performing funds found their own ways to limit the pain from rising interest rates. As 2022 began, John Lekas, chief executive of Leader Capital in Vancouver, Wash., pushed more of his investment- grade fund's money into bonds with floating interest rates. Because the yield on these bonds – largely issued by banks – rose alongside the Fed's target rate, prices fell less than those of ordinary corporate bonds, which have fixed coupons.

The move cut the fund's **duration** – expressed as a weighted average of how long it will take to receive all of the bonds' payouts – from more than four years in 2021 to less than one-quarter of a year today, helping absorb the blow that struck most peers. The fund's 7.4% return since the start of 2022 made it by far the best performer in Morningstar's core-plus category.

"When the Fed in 2021 started talking about transitory inflation, we didn't believe that," Lekas said. "Inflation is a hard bug to kill and it always has been."

Strategies with little exposure to rising interest rates did the best. Loan funds, which mostly buy floating-rate debt, returned 3.3%, and funds that focus on ultrashort-term debt returned 2.4%. Two funds specifically designed to achieve outsize benefits when rates rise, the Simplify Interest Rate Hedge ETF and the FolioBeyond Alternative Income and Interest Rate Hedge ETF, were the best performers that Morningstar tracked, returning 73% and 40%, respectively.

Funds specifically **focused on long-term bonds and lower-yielding government debt** – those with the most to lose when rates rise—were the **biggest**

decliners. The Pimco Extended Duration Fund lost 36%, and the Vanguard Long Term Treasury Fund fell 27%.

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Fed Lifts Rates to Highest Level in 22 Years

by Nick Timiraos – WSJ – Jul. 27, 2023

Powell says too soon to tell if latest rise is the last one needed in inflation battle

The **Fed**eral Reserve resumed **lift**ing **interest rates** Wednesday with a **quarter-percentage-point** increase that will bring them **to** a **22-year high**.

Fed **Chair** Jerome **Powell said** it was **too soon** to **tell whether** the **hike would conclude** a **series of increases** aimed at cooling the economy and bringing down inflation. The central bank would decide whether to keep lifting rates based on how the economy fares in the months ahead, "with a particular focus on making progress on inflation," he said at a news conference.

The unanimous decision to **raise** the benchmark **federal-funds rate** to a **range between 5.25% and 5.5%** follows a brief pause in increases last month. It marks the **11th rate rise since March 2022**, when they lifted rates **from near zero**.

Markets were mixed after the Fed decision. The S&P 500 finished about flat Wednesday, while the tech-heavy Nasdaq moved slightly lower. The benchmark **10-year Treasury yield** fell to **3.850%** after climbing Tuesday to 3.911%.

At their previous meeting in June, officials held rates steady but penciled in two more increases this year. Fed officials are scheduled to meet three more times this year, with the next meeting in September.

The meeting was likely to keep market expectations of another rate rise later this year "priced as a coin flip," said Daleep Singh, a former executive at the New York Fed who is now chief global economist at PGIM Fixed Income. "Pricing the next set of decisions as a coin flip maximizes flexibility for the Fed to react to incoming data."

Inflation has retreated from a 40-year high hit last summer, with the consumer-price index climbing **3% in June from** a **year earlier**. That is **well below** the **June 2022 peak** of **9.1%**, **when gasoline prices** reached a U.S. record **average** of **$5 a gallon**.

Fed officials have been concerned that underlying price pressures may prove more persistent as a solid labor market allows workers to bargain for higher pay, making it harder to get inflation down further.

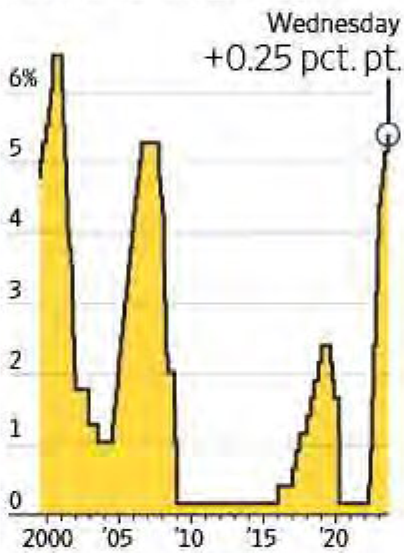
Core consumer prices, which exclude volatile food and energy categories, in June posted the smallest monthly gain in more than two years, according to the Labor Department's consumer-price index. But core prices rose 4.8% in June from a year earlier, a still-elevated level. Fed officials are focused on core inflation because they see it as a better predictor of future inflation.

Powell didn't rule out another rate rise at the central bank's September meeting, but he emphasized how much the central bank had already done along with the amount of time it can take for monetary policy to cool inflation.

"We've come a long way. Inflation repeatedly has proved stronger than we and other forecasters have expected, and at some point that may change," Powell said. "We have to be ready to follow the data, and given how far we've come, we can afford to be a little patient, as well as resolute, as we let this unfold."

Powell also said the Fed's influential staff no longer was forecasting a recession to begin this year, as they had in March, May and June, and instead was projecting a "noticeable slowdown" in growth.

Federal-funds rate target



Note: Midpoint of range since 2008
Source: Federal Reserve via St. Louis Fed

The **Fed seeks** to **keep inflation at 2% over time**, as measured by its preferred gauge, the personal**-consumption expenditures price index**. The Commerce Department will release the June update for that index on Friday. The Fed fights inflation by slowing the economy through raising rates, which causes tighter financial conditions such as higher borrowing costs, lower stock prices and a stronger dollar. The fed-funds rate influences other borrowing costs throughout the economy, including rates on mortgages, credit cards and auto loans.

The Fed boosted interest rates aggressively in 2022 and then slowed the pace at the end of the year. Holding rates steady in June offered a way to further dial down the pace of increases and study the effects of those rapid moves, particularly after fears that banking stress this spring might further constrain credit.

"For this last part of the tightening cycle, it makes sense to stretch it out over time. They are fine-tuning. They don't know the exact destination. It makes sense to do that slowly," said Angel Ubide, head of economic research for global fixed income at Citadel, a hedge-fund firm.

Officials had signaled disagreement in recent months over how to sequence their recent moves. While all 11 voting members of the policy-setting Federal Open Market Committee agreed to last month's decision to hold rates steady, some of the 18 voting and nonvoting officials would have supported a rate rise at the June meeting, according to a written account released earlier this month.

A few Fed officials have suggested they might prefer to raise rates again at the central bank's September meeting, while one had endorsed a longer pause. Others who think the impact of the Fed's rate increases has yet to take full effect are more likely to favor waiting until November or December to decide whether another increase will be appropriate.

"We think this will be the last hike" because inflation will continue to slow and the labor market will soften, said Matthew Luzzetti, chief U.S. economist at Deutsche Bank. But the economy has continued to defy expectations of such slowing for a year, creating a risk that the Fed lifts rates again, he said.

Even if Wednesday's increase marked the finish line, there was little incentive for Powell to validate those expectations until officials see more evidence that inflation and economic activity has slowed.

A slowdown in core inflation over the coming months could create a new conundrum for the Fed if officials see reasons to think the improvement will be short lived – for example, because wage growth stays firm.

"This is the old, 'be careful what you wish for,'" said Richard Clarida, who served as Powell's second-in-command from 2018 until January 2022.

Economists have debated over the past year to what extent slowing labor demand will require joblessness to rise or whether most of the adjustment can occur as companies reduce job openings but not head count.

"A lot of the debate on the labor market is beside the point," Clarida said. "If I was still over there, what I would worry about is the following: If we don't get a deceleration in wages and we don't get a pickup in productivity, then we're not going to hit our inflation target."

The **Fed's staff no longer forecasts** a **recession to begin this year**.

Fed Chair Powell said Wednesday that 'given how far we've come, we can afford to be a little patient, as well as resolute.'

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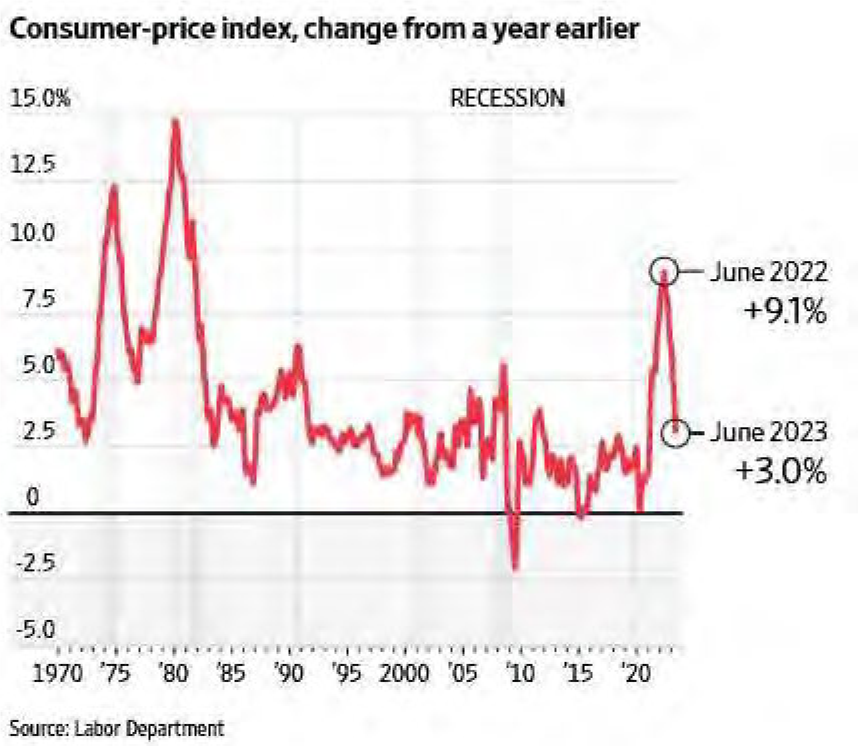
Inflation Cools to Slowest Pace Since 2021

by Gwynn Guilford and Nick Timiraos – WSJ – Jul. 13, 2023
Christian Robles contributed to this article.

Chances grow that Fed will halt raising rates after expected increase this month.

Inflation cooled last month to its slowest pace in more than two years, giving Americans relief from a painful period of rising prices and boosting the chances that the Federal Reserve will stop raising interest rates after an expected increase this month.

The **consumer-price index climbed 3%** in **June from** a **year earlier**, the Labor Department said Wednesday, **sharply lower than** the recent peak **inflation rate** of **9.1%** in **June 2022**, **when gasoline** prices hit a **U.S.** record **average** of **$5 a gallon**.

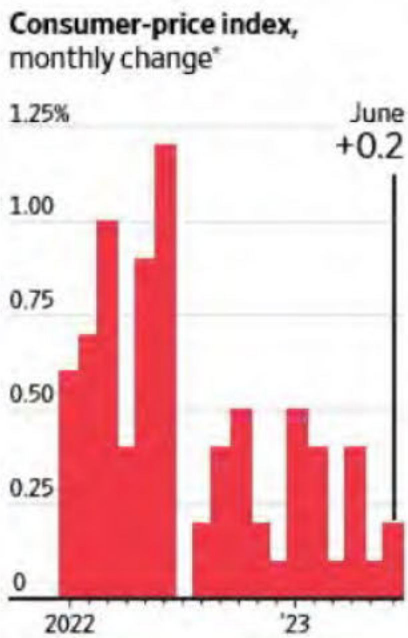


The June rate declined from 4% in May. Inflation was last close to 3% in March 2021.

"After a punishing stretch of high inflation that eroded consumer's purchasing power, the fever is breaking," said Bill Adams, chief economist at Comerica Bank.

Consumers paid less last month for used cars and airline fares, and their rent increased at the slowest one-month pace since early 2022. Prices for car insurance and recreation services rose.

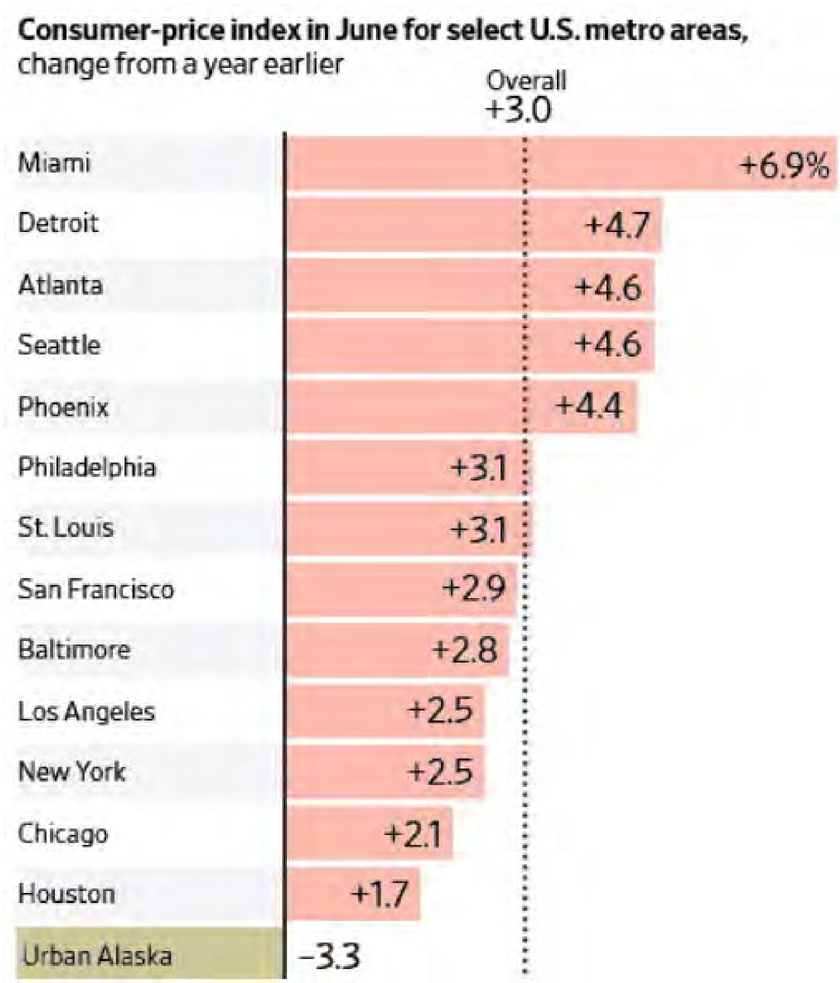
Investors cheered the figures, which affirmed the Fed was making progress in its work to stem high inflation. Stocks rose, with the S&P 500 climbing 0.7% and the Dow Jones Industrial Average adding 0.3%. Bond yields fell.



Fed officials are **on track to raise rates to** a **22-year high** at their **July 25-26 meeting** because economic activity hasn't slowed down as much as anticipated. But the inflation report calls into question whether the Fed will lift rates after that, as most officials projected last month.

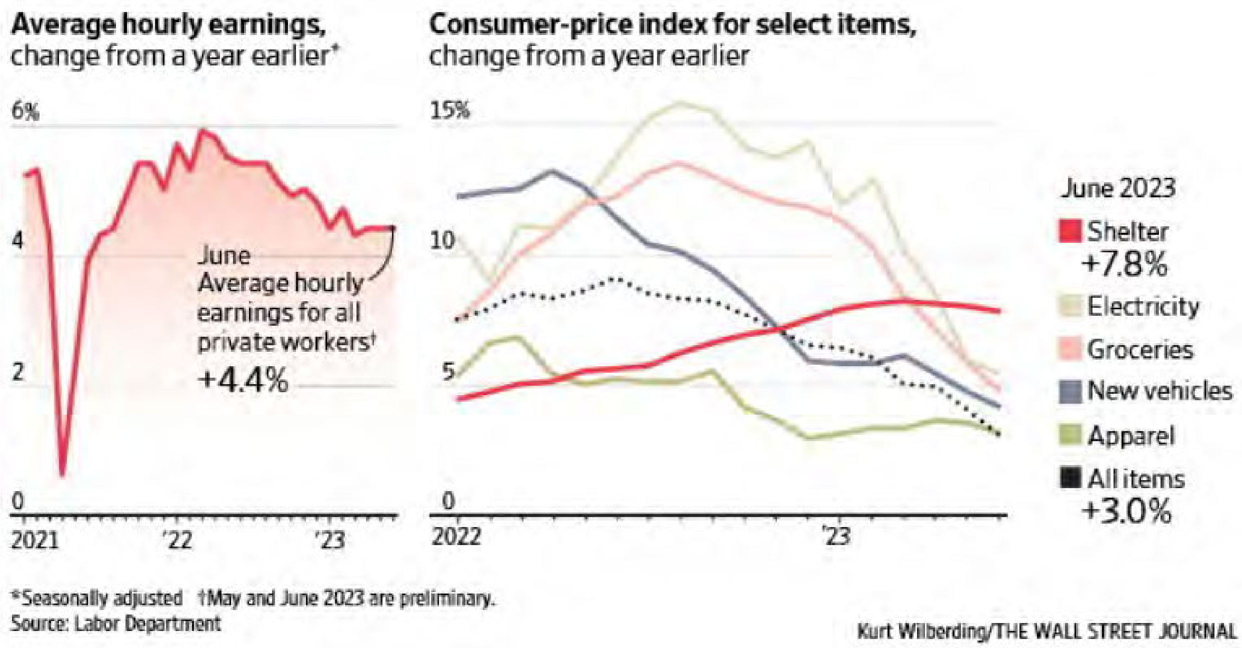
"My guess is that they're so locked in on another increase in July that they'll go ahead with that," said David Wilcox, senior economist at Bloomberg Economics and the Peterson Institute for International Economics. "The main effect it will have is to really fortify the argument around July's hike being the last of this campaign."

The U.S. economy remains resilient this year despite the Fed's rate increases, defying predictions of an economic downturn. **Hiring slowed** in **June but** was **still strong** and **unemployment historically low**. **U.S. economic output rose** at a **2.3% annual rate** during the just ended **second quarter**, **according to** the **Atlanta Fed**'s most recent estimate.



Left: The consumer-price index for many U.S. metropolitan areas in June remained above the national average on a year-over-year basis.

Fed officials have said that they don't want to overreact to one positive monthly inflation reading and will want to make sure a meaningful trend is beginning. Whether inflation keeps declining will depend on the economy weakening and price pressures ebbing in the months ahead.



The Fed seeks to keep inflation at 2% over time, as measured by its preferred gauge, the personal-consumption expenditures price index. Fed policy makers are likely to take comfort from the June report because core prices, which exclude volatile food and energy categories, posted the smallest monthly gain in more than two years. The core CPI rose 4.8% in June from a year earlier, the slowest pace since October 2021, and down from 5.3% in May.

Fed officials are focused on core inflation because they see it as a better predictor of future inflation than the overall inflation rate.

Last month they kept their benchmark federal-funds rate in a range between 5% and 5.25%. That decision marked their first pause after 10 consecutive increases since March 2022, when they raised it from near zero.

Overall consumer prices increased a seasonally adjusted 0.2% in June from the prior month, compared with May's 0.1% gain. Core consumer prices climbed 0.2%, just slightly above their pace in February 2021 at the start of the inflation surge. A more narrow measure of inflation that excludes goods, housing and energy was essentially flat in June from the prior month, according to Wall Street Journal calculations.

"Prices are going up at a slower rate overall, so the good news is that things are not getting worse for American consumers. But that doesn't mean they're necessarily getting all that better," said Leo Feler, chief economist at research firm Numerator.

While inflation is much lower than a year ago, it continues to take a toll on many consumers.

Ali Salim, 34 years old, said rising prices for rent and gasoline have squeezed his budget. His landlord raised the rent 24% last year on his one-bedroom apartment in a

Seattle suburb, then another 10% this year, he said. Salim said he decided to move to a new, smaller apartment, which has fewer amenities and is 8 miles farther away from the office where he works as a solutions architect at a tech company.

"I'm going to have to drive further and spend a bit more on gas," he said. Washington state has the highest gasoline prices in the nation at an average of $4.96 a gallon of regular unleaded, according to OPIS, an energy-data and analytics provider, well above the U.S. average of $3.54 a gallon.

Salim said increased expenses leave him saving about 40% of his salary, compared with about 60% before the rent increase last year. "My goal was to own a home within the next five years," he said. "With me saving so much less, I don't know if I'll be able to do that."

Prices increased modestly since late May as inflation showed signs of easing, according to the Fed's regular survey of the economy, known as the Beige Book, released Wednesday. **Some businesses** were **reluctant** to **raise prices because consumers** have grown **sensitive to inflation while others found** that **solid demand allowed them** to **maintain profit margins**.

June's drop in the inflation rate largely reflected favorable year-over-year comparisons. Last summer's price surge meant that a mild increase last month from May translated to a sharp decline in the year-over-year rate.

The comparisons will turn less favorable later this year, meaning year-over-year inflation rates might not slow much further until early 2024.

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Pension Funds Get Dinged as Alternative Assets Cool

by Heather Gillers – WSJ – Jul. 26, 2023

Alternative assets such as private equity paid off year after year for public pension funds over the **past decade**. That **winning streak** has **ended**.

For the first time since the 2008-09 financial crisis, **benchmark private-equity returns turned negative for** the **year ending March 31**, the period most pension funds report in their annual statements, according to a Burgiss Group index that excludes venture capital.

The **California P**ublic **E**mployees' **R**etirement **S**ystem, the **nation's largest pension fund**, said last week that **both private equity and** so-called **real assets such as real estate lost money** during its **latest fiscal year**. The declines come as companies are under pressure from rising rates and losses on office properties are dragging down real-estate returns.

"It's been a tough 12 to 15 months" for private equity and real estate, said Rebecca Sielman, principal and consulting actuary at pension consultant Milliman.

Public retirement systems, which manage more than $5 trillion in retirement savings for teachers, firefighters and other public workers, expect to report overall gains for their portfolios, driven mostly by stocks. That is after pension funds lost 7.9% during the previous fiscal year as stock and bond markets tanked.

Calpers last week reported a **preliminary return** of **5.8%** for the **fiscal year ended June 30**. The **Virginia Retirement System** estimated its return at approximately **5%**, though the exact figure won't be available until late August. The **Tampa** Firefighters & Police Officers **Pension Fund** – which **invests only in stocks and bonds** and **avoids alternative assets** such as private equity – reported a **15.8% return** for the **same period**.

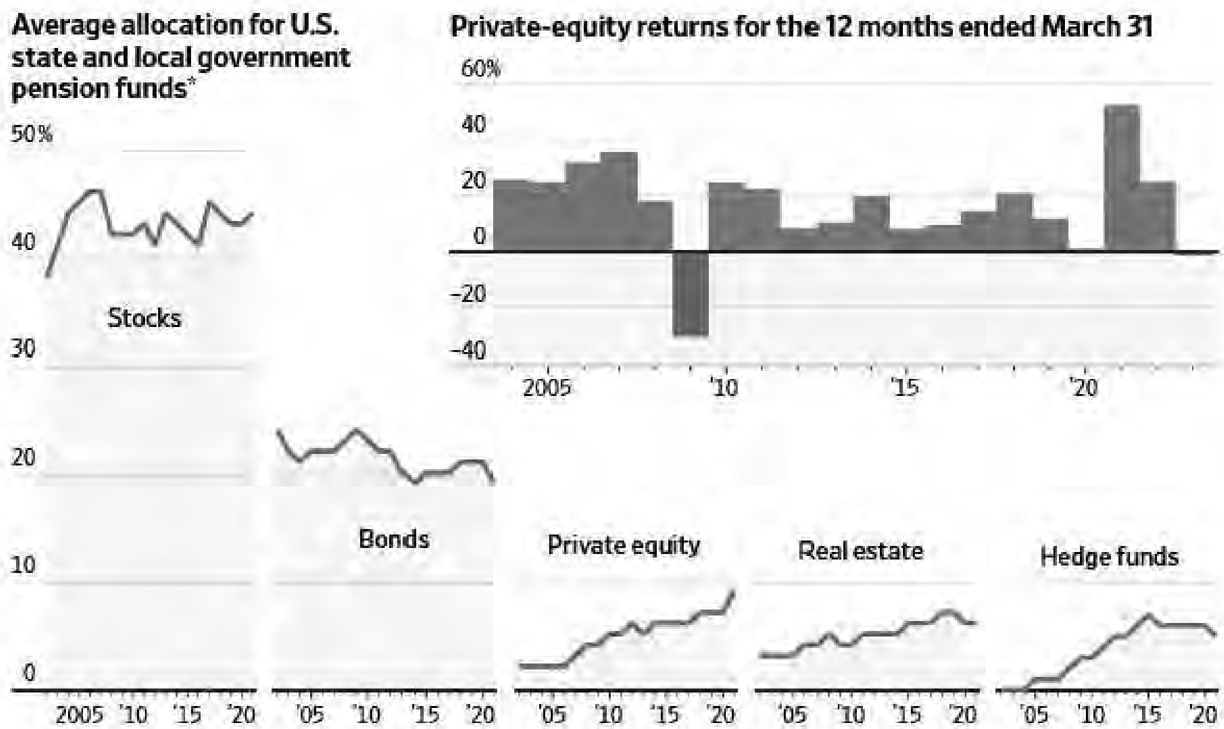
State and local pension funds pushed into riskier alternative assets during two decades of low rates in hopes that their returns could cover the cost of promised future benefits. A lter-native asset allocations rose to an average 22% of total assets in 2021 from 6% in 2002, according to the Boston College Center for Retirement Research.

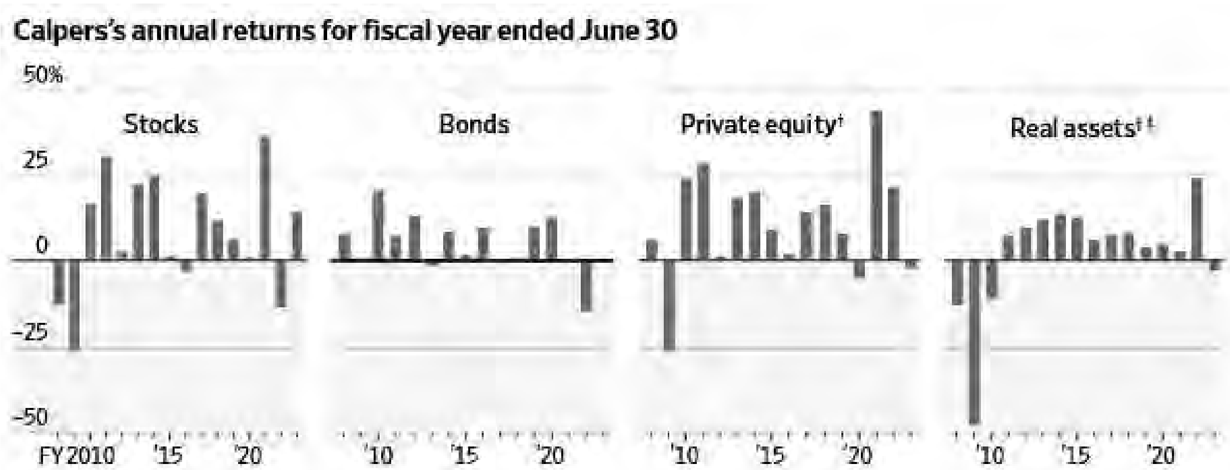
In contrast to **traditional stocks and bonds that trade daily**, **alternative assets generally require** a **commitment of five to 10 years**. With private equity, pension funds typically give money to a manager who pools it to buy, overhaul and sell companies, and then expect to receive a lump sum payout after a decade or so.

At Calpers, a newly created private-credit portfolio was the only alternative asset to produce gains this year. Private-credit managers pool loans to companies—often those that are being overhauled by private- equity managers. The asset has attracted a rush of pension money as interest rates have climbed.

Institutional investors such as pension funds have in recent years helped fuel a boom for private market managers like Apollo Global Management and Blackstone, which saw its assets under management top $1 trillion.

An average 10.3% of North American pension funds was allocated to private equity as of the end of 2022, according to Preqin data. An additional 9.4% is invested privately in real estate and 4.5% is invested in infrastructure such as toll roads and airports.





*Not all investment categories included.
†Reported on a one-quarter lag. ‡Returns for 2011 and prior reflect real estate only.
Sources: Boston College Center for Retirement Research (allocation); Burgiss Group (private-equity returns); California Public Employees' Retirement System (Calpers's annual returns)

This year's decline in private equity is a rarity for pension funds. The category delivered annualized returns of 14.8% over the 20-year period ended March 31, according to the Burgiss index. That compares with 10.4% for the S& P 500 over the same period. **Since 2009**, the **only time private equity lost money for Calpers before this year was** in **2020**, **when** the **Covid-19 pandemic hit**.

Since **illiquid assets such as private equity don't trade on public markets**, institutions rely on managers to provide quarterly estimates of what the investment is worth. Valuations are typically reported to investors a quarter late, so when pension funds report their returns for the 12 months ended June 30, the most common fiscal-year period, they reflect private-market performance for the year ended March 31.

Some analysts project private equity valuations will gradually price in losses from last year through the end of 2023.

"We do expect some headwinds in the next quarter," Calpers investment chief Nicole Musicco said last week. "We do expect to see some write-downs."

Some pension funds, including Maryland's state system, are reducing the amount of new money they invest in private equity each year. Others aren't backing away. The **California State Teachers' Retirement System**, the **nation's second- largest pension fund**, decided to bump up its private-equity target by 1 percentage point to 14% in May.

Calpers also is ramping up its private equity allocation, to 13% from 8%. "The private market area is still…a great space for us to lean into," Musicco said.

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PGE Names Joseph Trpik CFO

Co Press Release – S&P Global Market Intelligence – Jun. 15, 2023

Experienced energy executive brings over two decades of financial expertise.

Portland General Electric (**PGE**) (NYSE:POR) today announced the appointment of **Joseph** (Joe) **Trpik** as **chief financial officer** and **senior** vice president, effective June 30, 2023. Trpik **will succeed** PGE's CFO, **Jim Ajello**, who previously announced plans to retire and will serve as a senior advisor through August 31, 2023.

"We are pleased to welcome Joe to PGE," said **Maria Pope**, president and CEO. "At a time when the energy industry is becoming more complex, Joe's deep industry and financial expertise will be invaluable as we **invest for growth**, **manage costs** and deliver safe, reliable, affordable and clean energy."

Trpik comes to PGE with more than 20 years in senior leadership with Exelon, one of the nation's largest utility companies serving over 10 million customers, where he served most recently as senior vice president and chief accounting officer. He **previously** was **senior vice president** and **chief financial officer** of **Exelon Utilities** as well as **senior vice president** and **chief financial officer** of **ComEd**, Exelon's largest utility subsidiary. In these roles, Trpik had direct responsibility for financial planning and analysis, capital allocation, cost management, risk management, financial systems, accounting, tax and investor communications, among other functions. Trpik holds **B**achelor of **S**cience degrees in **Finance** and **Accounting** from Florida State University.

"I am thrilled to join PGE at a pivotal moment as the company is both leading the clean energy transition and building a smarter, more integrated grid," said Trpik. "I look forward to working with the team to build on PGE's momentum, driving growth and creating value for shareholders and customers alike."

About PGE and the Company's Safe Harbor Statement Are Not Reproduces Herein.

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PNM Resources

PNM Resources and Avangrid Agree to Merger Extension

Co. Press Release – S&P Global Market Intelligence – Jun. 20-, 2023

PNM Resources (NYSE: PNM) **and Avangrid** have **mutually agreed** to an amendment and **extension** of their **merger agreement through December 31, 2023**. The agreement **can be further extended** by **three months upon mutual agreement** from the companies.

The companies' merger agreement was announced in October 2020 and has **approval from five federal agencies and** the **P**ublic **U**tility **C**ommission of **Texas**. A stipulated agreement providing more than $300 million in benefits to New Mexico customers and communities was **rejected by** the **NMPRC** in December 2021 and has been under **appeal with** the **New Mexico Supreme Court**.

"Our merger with Avangrid remains the right path for the future of our customers, communities, employees, shareholders and the environment," said Pat Vincent-Collawn, PNM Resources Chairman and CEO. "Throughout the process to amend and extend the merger, we continued to prioritize the financial strength of our standalone business, ensuring we provide reliable and affordable service and delivering results.

The **New Mexico Supreme Court** has **scheduled oral arguments** in the case to be held on **September 12, 2023**. The **Court does not have** a **statutory deadline** for a **decision on** the **appeal**. Filings pertaining to the Court appeal, along with the NMPRC application, are available at https://www.pnmresources.com/investors/rates-and-filings.aspx.

Background, about the utilities and safe harbor statement omitted.

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Quarterly Earnings Expected to Be Worst in Years

By Peter Santilli and George Stahl – WSJ – Aug. 7, 2023

Earnings for the nation's biggest companies are poised to fall for the third straight quarter, hurt in part by the decline in energy prices.

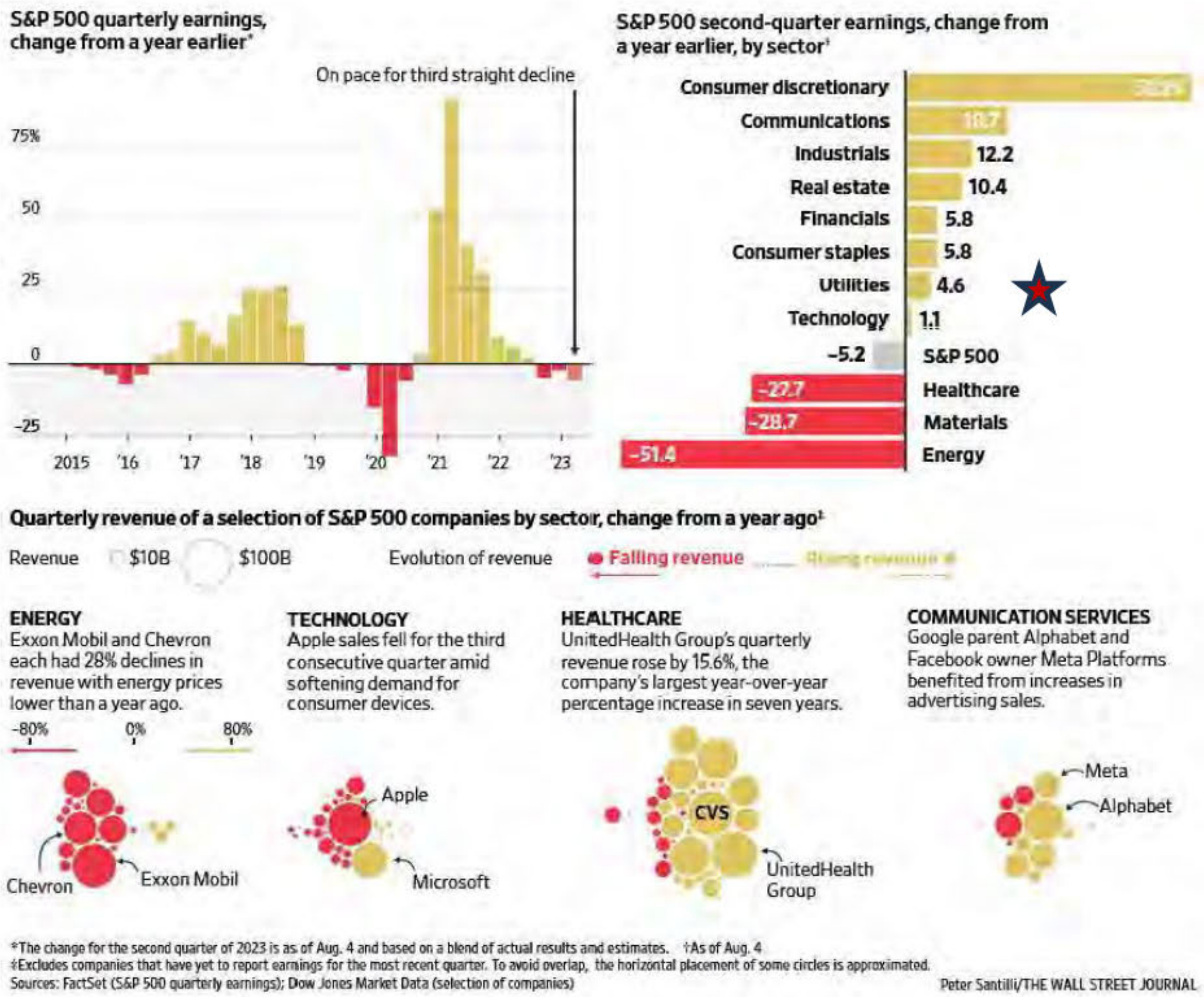
The members of the **S&P 500** are **on pace** to **collectively report** a **5.2% decline** in **earnings**, their **worst performance since 2020**.

Revenue is on track to rise 0.6% from a year ago, according to FactSet.

Energy companies are pulling down the index as their results have fallen from the record-breaking levels reported a year ago. However, they remain strong by historical standards.

"Obviously, gas prices were down, but I think refining margins are down a bit but still in very healthy territory," Exxon Mobil Chief Executive Darren Woods said on the company's earnings call last month.

Exxon's earnings fell by 56% from a year ago on a 28% drop in revenue.



Through Friday, 84% of the S&P 500 companies have reported results for the second quarter of 2023, and some big names remain, including Walt Disney on Wednesday, Walmart on Aug. 17 and Nvidia on Aug. 23.

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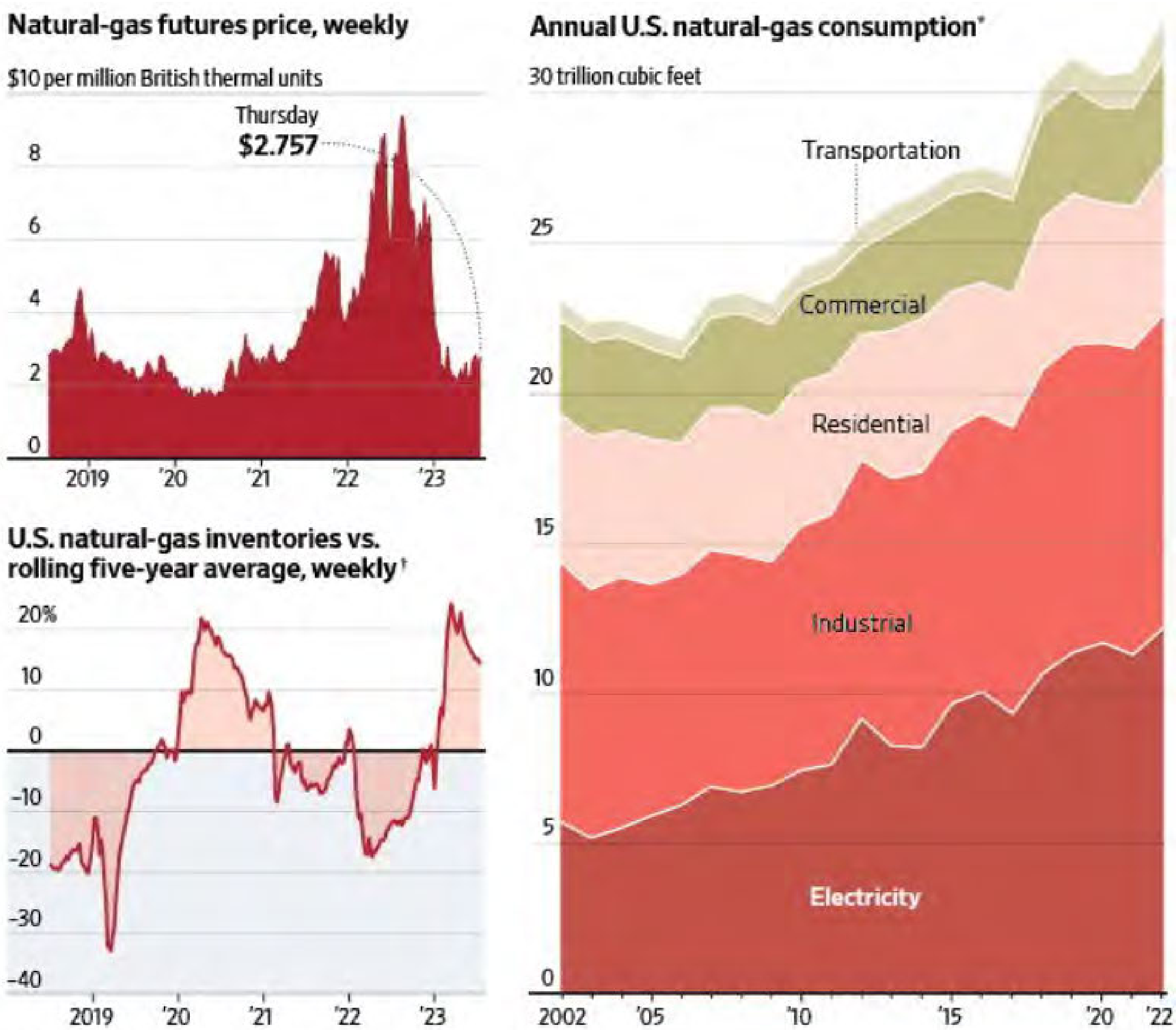
Summer Heat Isn’t Cranking Up Consumers’ Natural-Gas Bills

by Ryan Dezember – WSJ – Jul. 21, 2023

Americans are **burning more natural gas than ever to stay cool this summer**. Unlike the past two summers, when sweltering weather sent gas surging, the heat wave has hardly moved prices for the power-generation fuel.

Benchmark **natural-gas prices** have **stayed** in a **tight range** that is roughly **60% lower than** a **year ago**, when prices exploded to shale-era highs. Prices are **30% less than** in **July 2021**.



*2022 data are preliminary †Lower 48 states
Sources: Dow Jones Market Data (futures); Energy Information Administration (consumption, inventories)

Bill payers can thank the unusually warm weather this past winter for leaving a lot of gas unburned. As well, strong renewable-electricity generation has taken pressure off gas-fired power plants in some of the hottest parts of the country, including California and Texas.

Natural-gas futures for August delivery ended Thursday at $2.757 per million British thermal units, down 65% from a year earlier. Futures shed 1.5% so far in July, when they usually rise.

On-the-spot prices in some big markets, including Chicago and New York, have been even cheaper than the national benchmark, which is set at the Gulf Coast hub near export terminals and gas-consuming chemical plants. **Prices for coal** – competition for gas in many power markets – have **plunged** from record highs notched last year. If stifling heat lingers into August, prices could reach $3, said Joe DeLaura, senior energy strategist at Rabobank. Yet he expects a quick retreat and that prices should trade between $2.25 and $2.85 until winter.

Heat Isn't Boosting Gas Bills

"Hedge fund guys see $2.90, $3 as the upper end," DeLaura said. "If we get around $3, everyone is going to sell."

Bank of America analysts predict summer prices will average $2.75. Goldman Sachs forecasts $2.90 for the remainder of the season. Trading firm Ritterbusch & Associates suggested this week that clients liquidate bets that prices will rise in August.

The **big difference between now** and the **past couple of summers** is that there is **much more gas available**.

The **volume** of **gas in U.S. storage caverns** last week was **14% greater than** the **five-year average**, according to the Energy Information Administration. July inventories haven't been so high relative to average since 2016, when the market was burning off a glut following a warm winter that was attributed, as now, to the El Niño climate pattern.

In 2021, Texas froze over, boosting demand and icing over a lot of wells. Gas stockpiles were much smaller than what they had averaged over the previous five years by the time air conditioners were turned on. Scorching weather kept depleted caverns from refilling enough before winter, when gas is needed to heat homes.

Last year, Russia's invasion of Ukraine shocked energy markets and sent European buyers racing to replace Russian gas. Those buyers bid up cargoes of liquefied natural gas, or LNG. Prices climbed at home to compete with the export market.

U.S. LNG exports declined when a **big Texas export facility caught fire in June**, knocking it out of commission until earlier this year. Maintenance shutdowns at other export facilities have lately decreased shipment volumes.

Europeans aren't buying like they were last year. Between their LNG binge, a winter to match North America's for mildness and extraordinary energy-conservation measures, Europe has full tanks. **Natural-gas storage** in the **European Union** is nearly **80% full**, according to Commerzbank analysts.

U.S. producers idled rigs in gas-drilling regions, including Appalachia and Louisiana's Haynesville Shale. There were **133 rigs drilling specifically for natural gas last week**, **down 17% from 161 in late April**, according to oil-field services firm Baker Hughes.

The Federal Reserve Bank of Kansas City said last week that drillers polled in its district said, on average, that they need $3.49 per million British thermal units to drill profitably in gas fields from Wyoming to Oklahoma.

The EIA said it expects daily U.S. output to hit a record this month. But it forecasts lower production in August when declines in Oklahoma, Appalachia and Louisiana outpace gains in places such as West Texas, where gas is unearthed as a byproduct of oil drilling.

Last July set a record for the amount of gas burned to produce electricity. The EIA said it expects consumption to rise 4% from last year, in part due to newly operational gas-fired power plants. The EIA estimates gas will account for 46% and 47% of all power generation in July and August, respectively.

Unlike the past two summers, this year's heat wave has hardly moved natural-gas prices.

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U.S. Economic Growth Accelerates, Defying Slowdown Expectations

by Sarah-Chaney-Combon and Christian Robles – WSJ – Jul 27, 2023

Economy grew 2.4% last quarter, suggesting the U.S. is steering clear of recession.

Consumer spending has been fueling the U.S. economy.

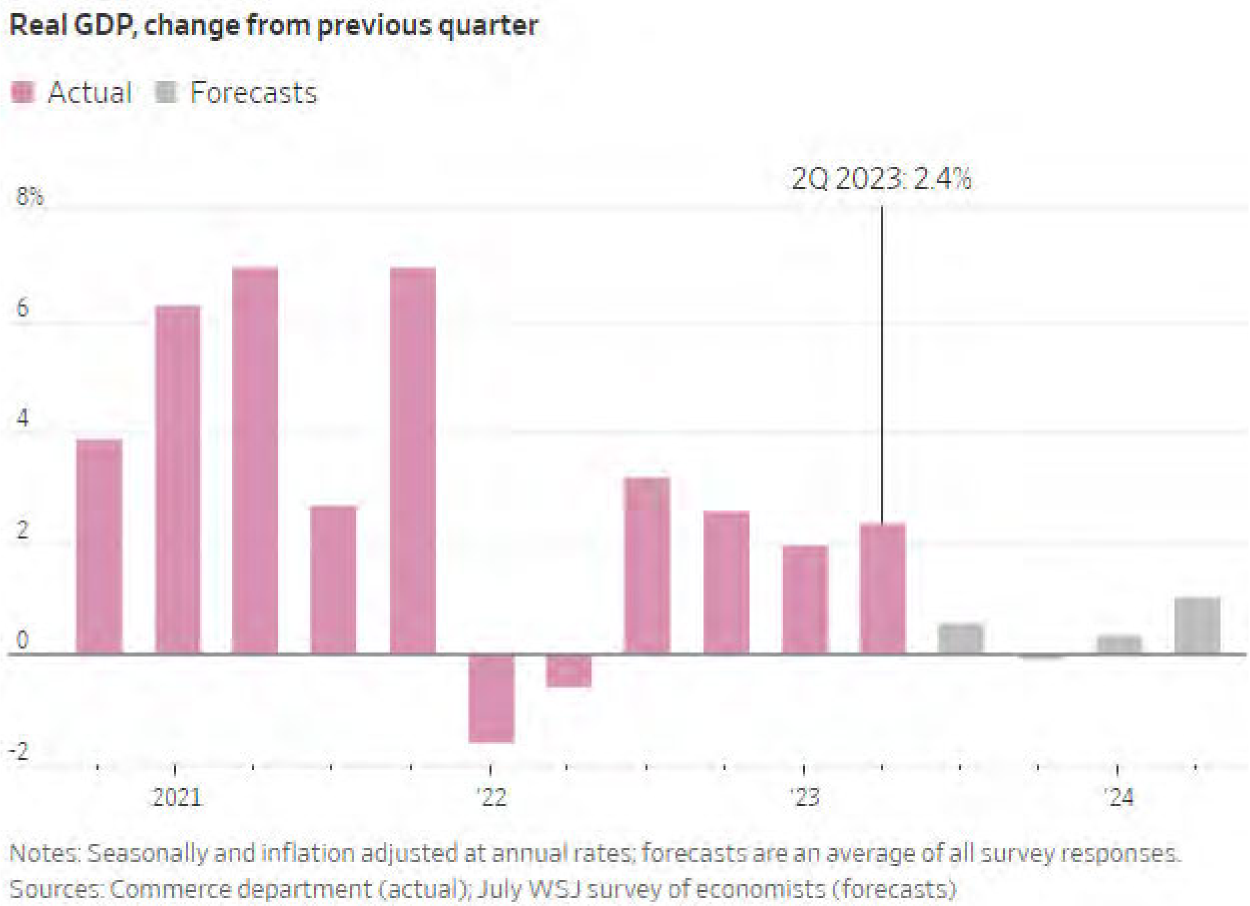
The U.S. economy picked up last quarter and remained well clear of a recession despite the Federal Reserve pushing interest rates higher.

Gross domestic product grew at a seasonally and inflation adjusted annual rate of **2.4%** in the **second quarter**, picking **up slightly from 2% growth** in the **first three months** of the **year**, the Commerce Department said Thursday.

Consumer spending grew this spring, **but** at a **slower pace** for **both goods and services**. **Business investment strengthened from April through June**, with companies spending solidly on buildings and equipment. **Companies rebuilt inventories**, helping boost output.

Final sales to private domestic purchasers, a measure of consumer and business spending that gauges underlying demand in the economy, grew at a 2.3% annual rate in the second quarter, a solid pace but a slowdown from 3.2% growth in the first quarter.

Overall, the GDP report adds to evidence the economy remains resilient amid higher interest rates. The **labor market** is **still tight**, and **inflation is easing**.



Economists are now **dialing back** their **recession expectations** after many had projected a downturn would start in the middle of the year in response to Fed policy. The Fed acted to raise its benchmark interest rate to a 22-year high on Wednesday. Chair Jerome Powell didn't rule out another increase, but emphasized the amount of time it can take for higher interest rates to cool inflation.

"We've turned the corner on the risk here, and instead of being heavily weighted to recession, it's balanced between recession and not recession," said Amy Crews Cutts, chief economist at AC Cutts & Associates, before the data was released.

Consumer spending fuels the economy

Consumer spending grew at an **annual rate** of **1.6%** in the **second quarter**, **down from 4.2% growth** in the **first quarter**. The slowdown largely reflected cooling purchases of big-ticket items after Americans snapped up vehicles at the start of the year as they flowed back onto dealership lots.

Americans are benefiting from a strong labor market in which wage gains recently surpassed cooling inflation. **Initial claims**, a **proxy for layoffs**, **declined** by 7,000 last week to a seasonally adjusted 221,000, the Labor Department said Thursday. That is a

historically low level that essentially **matches** the **2019 average when** the **labor market** was **also strong**.

Gus Ayala, a 73-year-old retired banker, is still spending despite higher interest rates and prices. The El Mirage, Ariz., resident plans to buy a hybrid car later this year and will likely finance the vehicle, rather than pay in cash for it. He and his wife's savings buffer is helping pay for his wife's upcoming trip to Iceland.

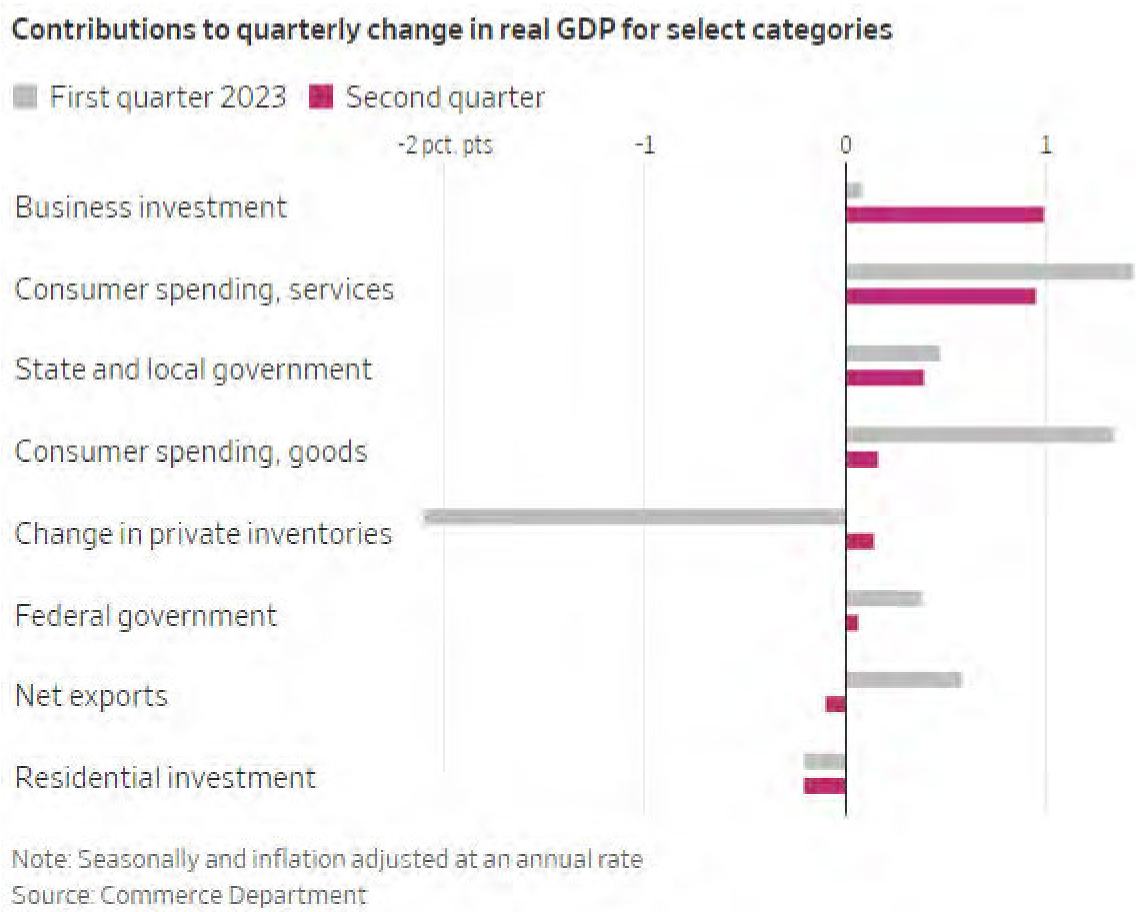
"We want to go spend money on what benefits us and allows us to enjoy our life," Ayala said.

Ayala changed some of his spending habits to cope with elevated inflation. He switched to a cheaper brand of coffee, Seattle's Best, earlier this year after the cost of a 12-oz bag of Peet's shot up to $12 from $9 last year. Ayala still needs his daily coffee fix, he said, while sipping his morning cup of joe.

Whether consumers will spend at the same pace later this year isn't clear. High-interest rates will persist, making vehicles, appliances and other products Americans often take out loans to buy more expensive. **Student-loan repayments** are **set** to **resume later this year**. **Americans are running through** the stash of **savings** they built up while at home earlier in the pandemic.

"There are a lot of canary-in-the-coal-mine signs that we're due for a slowdown in consumer spending," said Brett Ryan, senior U.S. economist at Deutsche Bank Securities.

Powell: Full Effects of Tightening Rates Yet to Be Felt



Federal Reserve Chair Jerome Powell said on Wednesday that the central bank will raise its benchmark interest rate by a quarter percentage point, bringing U.S. rates to their highest point in 22 years.

Investment figures show impact of interest rates

Business investment grew at an **annual rate** of **7.7%** in the **second quarter**, **up sharply from 0.6%** in the **first quarter**.

Some long-term forces are helping boost investment despite higher interest rates. A surge in federal spending on chip-manufacturing plants and electric-vehicle factories is offsetting some other cutbacks.

Net trade slightly subtracted from second-quarter growth, reflecting a sluggish global economy. Residential investment declined for the ninth consecutive quarter. Recent declines in residential investment reflect housing-market strains amid higher mortgage rates.

Still, a long-running shortage of previously owned homes is helping support new construction. The worst of the housing-market downturn could be in the rearview mirror.

With more construction in the pipeline, residential investment could grow in the coming months.

More upbeat outlook

Consumers, businesses and economists are feeling more optimistic about the outlook. As inflation falls from historic highs and the labor market remains tight, the prospect of a soft landing – in which inflation returns close to the Fed's 2% target without a recession – appears more probable.

U.S. consumer confidence continued to improve in July, with many Americans expressing more optimism about the future, the Conference Board said this week. Consumers worried less about a recession.

Small businesses are feeling less downbeat about the economy. In July, 37% of small businesses said they believe the economy will worsen in the next 12 months, the best recording since February 2022, according to Vistage Worldwide, a business-coaching and peer-advisory firm.

Economic growth in the U.S. and globally this year is likely to be stronger than previously estimated, the International Monetary Fund said Tuesday. The improved outlook reflects labor-market strength, strong spending on services such as tourism and diminished financial stability risks.

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What's Behind Washington County's Wage Decline, Among Nation's Steepest?

by Mike Rogoway – Oregonian – Jun. 20, 2023

Washington County sits at the heart of Oregon's economy.

It's **home** to **Intel**'s multibillion-dollar factories, **Nike**'s headquarters campus, **Columbia Sportswear**'s corporate offices and a sea of office parks.

So it could be a worrisome sign for the state that Washington County posted one of the nation's biggest declines in average wages last fall.

Average weekly wages in **Washington County fell** by **4.3%** in the **last three months** of **2022**, according to new federal data. That **ranks 319th among** the **country's 356 largest counties**.

Other big West Coast counties fared even worse, especially those like King County in Washington state, that have high concentrations of tech workers.

U.S. 356 Largest Counties		Employment			Average Weekly Wage		
OR County	(000) Thousands Establishments	(000) Thousands Dec. 2022	% Δ Dec. 2021 Dec. 2022	Ranking by % Δ	2022 Q4	% Δ 2021 Q4 2022 Q4	Ranking by % Δ
Clackamas	18.4	172.5	2.5%	114	1,325	-3.6%	306
Deschutes	11.8	89.1	2.1%	149	1,206	0.8%	59
Jackson	8.8	89.9	1.2%	239	1,062	-1.8%	216
Lane	14.4	155.7	1.2%	239	1,090	-2.2%	242
Marion	13.0	163.9	2.5%	114	1,143	-2.0%	231
Multnomah	43.1	503.2	1.1%	250	1,488	-2.4%	255
Washington	23.8	309.0	3.5%	48	1,616	-4.3%	319
U.S.	11,785.7	152,317.9	2.6%	-	1,385	-2.3%	-

Source: Oregonian, drawn from U.S. Bureau of Labor Statistics (BLS) Economic Releases
Table 1. Covered establishments, employment, and wages in the 356 largest counties, fourth quarter 2022 - 2022 Q04 Results (bls.gov)

Scores of big tech companies announced layoffs last fall, among them Facebook, Amazon, Google and Intel. In California's Silicon Valley, Santa Clara and San Mateo counties suffered annual wage declines of 15.0% and 20.7%, respectively.

Are layoffs at Intel and other **tech** companies **responsible** for Washington County's poor showing, too**?**

No, says **Amy Vander Vliet**, economist with the **Oregon Employment Department**. She crunched the numbers and found that tech manufacturing jobs in Washington County suffered a relatively modest decline in average pay, of about 2%.

"High tech manufacturing and another high-tech industry, information, saw wages decline at a steep pace nationally," Vander Vliet said. "Less so in Washington County."

Washington County's biggest decline came in a **broad industry category called** "**professional and business services**." These are white-collar jobs, Vander Vliet said – architects, civil engineers, lawyers and the like – and contractors filling administrative jobs. And she said Washington County has a high concentration of those workers.

Professional and business services added jobs in **Washington County** last fall, **but** the **jobs** it **added paid less** – and brought down the county's overall average wage. Another industry, "financial activities," cut jobs and wages at the end of last year. That was another big contributor to the county's shrinking average.

Though Washington County had the biggest wage drop among Oregon's largest counties, it was far from alone. **Clackamas and Multnomah counties** each posted **wage declines, too**, and **wages** were **down** by **2.3% nationally**.

The U.S. decline surprised economists because other metrics show wages are rising – in Oregon and across the country. It's not clear exactly why the latest numbers fell, but Vander Vliet has some theories.

"I know that bonuses were down last year, holiday bonuses, were down nationally," Vander Vliet said.

The latest federal data, known as the Quarterly Census of Employment and Wages, includes stock incentives, bonuses and other compensation that doesn't come with the weekly paycheck and isn't counted in other metrics.

Many companies were anticipating a recession in 2023 and some investors were, too, depressing share prices and reducing the size of bonuses and the value of stock options.

Additionally, Vander Vliet said a continued uptick in retirements may explain why the average wage is dropping as those older workers walk out the door.

"They earn a lot of money, and when they leave, their replacements might … earn less than they do," Vander Vliet said.

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Productivity Drop Blurs Economic Picture

by Gwynn Guilford – WSJ – Jun. 5, 2023

You would think from May's blowout jobs report the economy was booming.

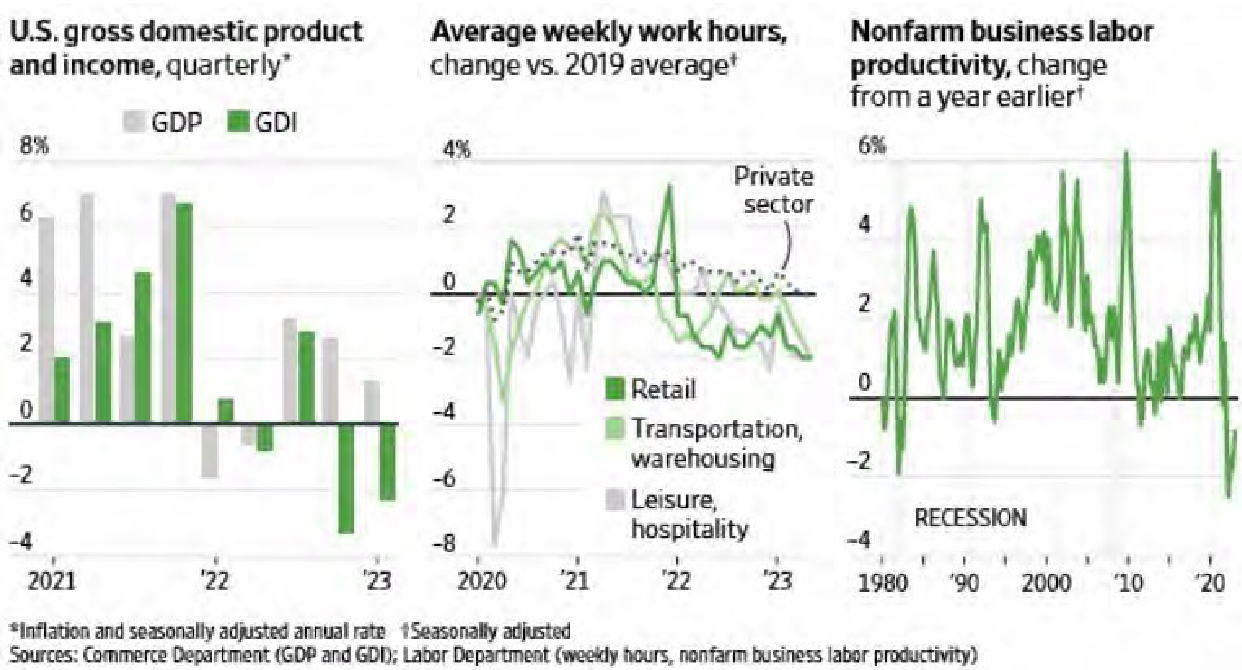
Here's the puzzle: Other recent data suggest it is in recession.

The dichotomy emerges from the **divergent behavior** of **employment and output**, two key indicators of economic activity. **In May**, **employers added 339,000 jobs**, bringing the **total number of jobs added this year** to **nearly 1.6 million**, a **gain** of **2.5% annualized**.

But real gross domestic income, a measure of **total economic activity**, **shrank** in both the **fourth quarter and** the **first quarter**. **Two negative quarters** of **output growth** are **one indicator** of a **recession**.

The economy has gone through periods where output has expanded faster than employment, but seldom the other way around, said Ryan Sweet, chief U.S. economist at Oxford Economics.

What explains these dissonant signals is **productivity, or output per hour worked**: It **is cratering**. That raises questions about whether the much-hyped technology adoption during the pandemic and, more recently, artificial intelligence are making a difference. It also raises the risk that the Federal Reserve will have to raise interest rates more to tame inflation.



Labor productivity fell 2.1% in the **first quarter from** the **fourth at** an **annual rate**, and was **down 0.8%** in the **first quarter from** a **year earlier**, the Labor Department said Thursday. That is the **fifth-straight quarter** of **negative year-over-year productivity growth**—the **longest** such run **since records began** in **1948**.

Those calculations are derived from **gross domestic product**, which shows output rising at a 1.3% annualized rate in the first quarter. But another key measure – **gross domestic income** – declined, implying an even bigger productivity collapse.

GDI is the yin to **GDP**'s yang, measuring incomes earned in wages and profits, while GDP tallies up purchases of goods and services produced. In theory, the two should be equal, since someone's spending is another's income.

They never exactly match because of statistical challenges. Lately, though, the divergence is dramatic. "Over the past two quarters, real GDP shows the economy expanding by 1.0%, not far off potential growth, whereas GDI shows it contracting by 1.4%, which amounts to a deportant cent-sized recession," said Paul Ashworth, chief U.S. economist at Capital Economics. The divergence is ominous: GDI previously undershot GDP dramatically during the 2007-09 financial crisis and in the early 1990s recession, Ashworth said.

The second quarter is also shaping up to be weak. **S&P Global Market Intelligence sees second-quarter real GDP expanding** at a **0.8% annual rate**; **Morgan Stanley projects 0.3%**. The **Atlanta Fed's GDP-Now model estimates 2%**. Most economists don't forecast GDI.

Usually, employment plummets during recessions because as factories, offices and restaurants produce less, they need fewer workers. That clearly isn't happening. "If you look at the early 2000s, that was what was called a 'jobless recovery,' because employment took a long time to come back even though the economy was growing," said Sweet. "This time around it could be the opposite – the economy could be contracting, but you're not seeing job losses."

One reason could be **labor hoarding**. After struggling to hire and train workers during the pandemic-induced labor crunch, employers are now balking at letting them go, even as sales slip, given the labor market's unusual tightness. There were **10.1 million vacant jobs in April**, well above the 5.7 million people looking for work that month. Some firms – particularly services such as restaurants and travel-related businesses – ran short-staffed for the past couple of years and are still catching up.

It's "not that technology got worse in the last year, but that businesses were selling less stuff and they're nervous about their ability to attract employees, so they're holding on to their employees," said Jason Furman, an economist at Harvard University who served in the Obama administration. It is also plausible, he said, that the shift to working from home generated a hit to productivity, whose impact grows with the cumulative loss of creative exchange and mentoring.

Productivity growth is im- in the long run because it is one of two engines of economic growth, the other being an expanding workforce. Sweet, the Oxford Economics economist, notes businesses have been spending on equipment, software and intellectual property, investments that should eventually raise productivity. Though it may take many years, so should recent advances in artificial intelligence.

Amore imminent concern is that when workers produce more, companies can raise wages without increasing prices. **When productivity falls**, it is **harder to keep inflation in check**.

This could make things even more **challenging for** the **Fed**. "Companies probably have the ability to pass on higher prices to consumers if they want to," said Neil Dutta, head of economic research at Renaissance Macro Research. "That would be problematic for the Fed."

Moreover, if GDI is a better indicator of output than GDP, "it would mean that the economy has slowed more than we had thought, without bringing down inflation that much," Furman said. That might mean it will ultimately take an even bigger economic pullback "to bring inflation down."

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In Oregon, New Law Adds Securitization to Utility Financing Toolbox

by Jason Lehmann – Regulatory Research Associates (RRA)
an Affiliate of Standard and Poor's Global Market Intelligence – Aug. 2, 2023

Oregon governor Tina Kotek on **Aug. 1 signed into law legislation** that will **allow** the **state's investor-owned electric and gas utilities** to **issue bonds** and

securitize debt for **costs and expenditures associated with declared emergency events** that have been **approved for recovery in rates**.

House Bill 3143 was introduced in January and passed by the Oregon legislature in late June.

Regulatory Research Associates views the new regulatory mechanism as constructive from an investor viewpoint. Securitization is viewed as an attractive financing option because it allows regulators to reduce the customer rate impacts related to the recovery of a particular utility asset.

- Oregon House Bill 3143 provides utilities the ability to securitize all or a portion of the costs incurred during declared emergency events, such as severe storms, pandemics or catastrophic wildfires, through the sale of high-rated, low-interest ratepayer-backed bonds.
- Prior to issuing any rate recovery bonds, **utilities must obtain** an **O**regon **P**ublic **U**tility **C**ommission **financing order** that is **contingent** upon a **commission determination** that the **expenditures sought for recovery** are **reasonable and prudent**. The **commission must issue** an **approval or denial order within 180 days of** a utility's **application**.
- First used widely within the energy utility industry in the 1990s to finance stranded costs associated with the implementation of retail competition for generation service in certain states, securitization has seen renewed interest in recent years, as utilities and their regulators address energy transition-related stranded costs, deferred balances associated with the COVID-19 pandemic and more episodic costs related to extraordinary weather events and disasters.

Prior to issuing any rate recovery bonds, the state's investor-owned utilities like Portland General Electric Co. PGE) must obtain an Oregon Public Utility Commission (PUC) financing order that is contingent upon a PUC determination that the expenditures sought for recovery are reasonable and prudent.

The PUC must issue an order within 180 days, in approval of or denial of a utility's securitization application.

PGE has **spoken** in **favor of** the **securitization bill**, as it worked its way through the Oregon legislature, describing the bill as one that "can help limit customer price impacts from major events. Affordability is essential with significant inflationary pressures and energy price volatility."

Oregon's electric utilities, including PGE, PacifiCorp and Idaho Power Co., and electric utilities in general in the US Northwest have experienced historic, destructive wildfire activity, ice and snowstorms, and other major events like the COVID-19 pandemic. These events, in turn, have led utilities to seek deferral, for eventual recovery, of the lost revenues and costs related to these events.

In February 2021, winter storms caused widespread damage to PGE's electric system, leaving hundreds of thousands of customers without power and millions of dollars in damages. PGE began collecting deferred amounts tied to these storms on

Jan. 1 over a seven-year period following an October 2022 stipulation approved by the PUC.

In June, PacifiCorp filed applications in Oregon and other states in which it operates for authorization to defer costs associated with third-party wildfire claims, following a June 12 Oregon circuit court jury that found the utility liable for a series of wildfires in its service territory in September 2020.

Oregon's other utilities include MDU Resources Group Inc.'s Cascade Natural Gas Corp., Avista Corp. and Northwest Natural Holding Co.'s Northwest Natural Gas Co.

Securitization overview

As it pertains to utilities, securitization refers to the issuance of bonds backed by a specific existing revenue stream that has been "guaranteed" by regulators and/or state legislators.

Securitization generally requires a utility to assign an eligible regulatory asset and a designated revenue stream for that asset to a "bankruptcy remote" special purpose entity or trust. In some instances, a state financing authority fulfills this role. The trust or financing authority in turn issues bonds that will be serviced by the transferred revenue stream. The proceeds from the bond issuance flow to the utility and, in many cases, are used to retire outstanding higher-cost debt and/or buy back common equity, thus lowering the company's weighted average cost of capital.

While it is unclear if securitization requires legislation, a specific legislative mandate generally improves the rating accorded securitization bonds and lowers the associated cost of capital, given that a legislatively supported revenue stream may be more difficult to rescind than a stand-alone order of a state commission. In RRA's experience, no state commission has authorized securitization in the absence of enabling legislation.

This method of financing is viewed as an attractive option because it allows regulators to minimize the customer rate impacts related to recovery of a particular utility asset. The carrying charge on the asset is the interest rate applied to a highly rated, usually AAA, corporate bond rather than the utility's weighted-average cost of capital or even the interest rate on typical utility bonds, which are generally rated BBB.

At the same time, securitization reduces the investment risk for the utility by providing the utility with up-front recovery of its investment, in what are usually non-revenue-producing assets. The company can then redeploy those investment dollars elsewhere.

RRA evaluation of Oregon regulation

RRA views Oregon regulation as relatively balanced from an investor perspective. Recent rate cases have been resolved through settlement negotiations, and most companies utilize a forward-looking test year. Adjustment clauses are utilized by the state's electric utilities for recovery of costs associated with renewable resources, and partial revenue decoupling mechanisms are in place for certain electric and gas companies.

Retail competition is in place only for large-volume nonresidential energy users, while small-volume customers continue to be served under a traditional regulatory paradigm. Electric and gas commodity cost recovery mechanisms are in place; these contain earnings tests and/or dead bands with cost-sharing provisions. Utility-related mergers have generally been approved by the PUC without onerous restrictions; however, the PUC has utilized various ring-fencing mechanisms designed to shield the regulated utilities from the diversified activities of their parent companies or affiliates. RRA accords Oregon an Average/2 ranking.

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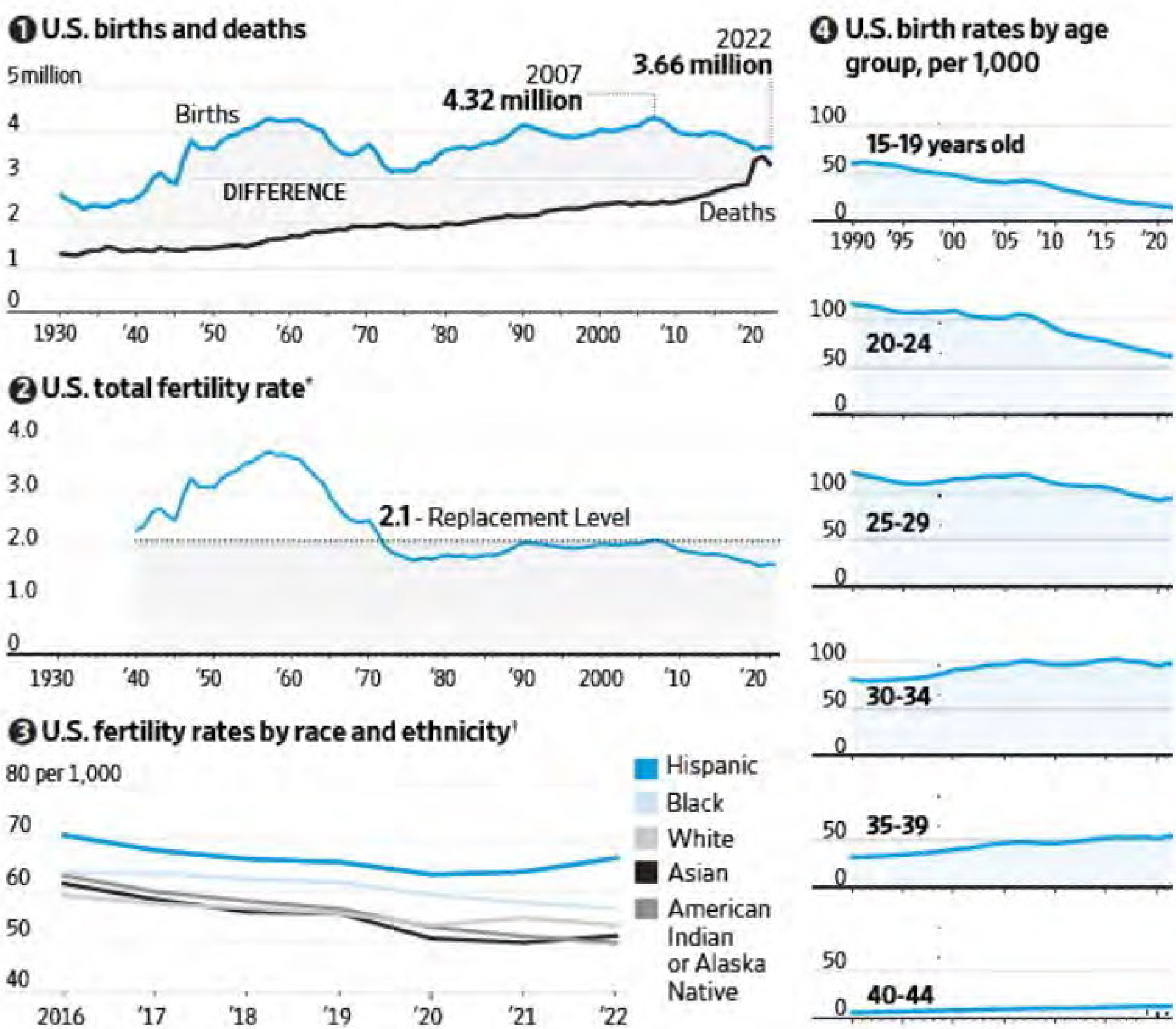
U.S. Births Held Flat in 2022

by Anthony Debarros – WSJ – Jun. 1, 2023

About 3.66 million babies were **born** in the **U.S. in 2022**, essentially **unchanged from 2021** and **15% below** the **peak** hit in **2007**, according to new federal figures released Thursday.

The provisional total – 3,661,220 births – is about 3,000 under 2021's final count, according to the Centers for Disease Control and Prevention's National Center for Health Statistics. Final government data expected this year could turn that small deficit positive.



Note: 2022 data are provisional. *An estimate of the average number of babies a woman would have in her lifetime
†Births for women aged 15–44 in specified group
Source: Centers for Disease Control and Prevention

Experts have pointed to a confluence of factors behind the nation's recent relative dearth of births, including economic and social obstacles ranging from child-care to housing affordability.

Absent increases in immigration, fewer births combined with continuing baby-boomer **retirements will likely weigh on** the **labor** force **supply within** the next **10 years**, said Kathy Bostjancic, chief economist at Nationwide, an insurance and financial-services company.

"You're going to have a real shortage of workers unless we have technology somehow to fill the gap," Bostjancic said.

A look at the trends:

1. **The government tallied –** about 655,000 fewer births in 2022 than at the 2007 high of 4.32 million, reflecting continuing decreases. Coupled with **still-elevated deaths** partly because of the latter part of the **Covid-19 pandemic**, the U.S. in 2022 saw only about 385,000 more births than deaths. The 2022 total may tick higher when final data is tallied this year. Final 2021 births were about 5,000 above the provisional number; for 2020.

2. **The total fertility rate –** closely watched because a level of **2.1 children per woman** is the "**replacement rate**" needed for a population to maintain current levels—was **1.665 in 2022**, essentially unchanged from **1.664 in 2021** and only a slight recovery from a record low in 2020.

   The U.S. has generally been below replacement level since the early 1970s.

3. **The general fertility rate for Hispanic mothers increased 4% in 2022**, second only to people of Native Hawaiian or other **Pacific Islander** origin. Fertility rates among **Asian** women **rose** 3%; rates for **all other groups fell**.

   Hispanic mothers accounted for 25.5% of U.S. births in 2022, a record, while the shares of births from non-Hispanic white and Black women declined. White women accounted for 50.1% of births in 2022, Black women for 13.9%, and Asian women for 6%.

4. **The trend of decreasing birthrates among younger women continued in 2022.** For teens **ages 15 to 19**, the birthrate **fell 3%**, and for ages **20 to 24** it was **down 2%**. The rate for the next oldest group, **25 to 29**, edged **up** only **slightly**. **Increases** were **mainly** seen **among women 35 to 44**. If trends continue, the birthrate for women ages 35 to 39 may soon eclipse the rate for ages 20 to 24.

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Why Americans Are Having Fewer Babies

by Janet Adamy – WSJ – May 27, 2023
Anthony DeBarros and Paul Overberg contributed to this article.

The U. S. birthrate is down sharply since 2007, as women say economic and social obstacles prevent them from having as many children as they want.

The number of babies born in the U. S. **started plummeting 15 years ago** and **hasn't recovered since**. What looked at first like a temporary lull triggered by the 2008 financial crisis has stretched into a prolonged fertility downturn. Provisional monthly figures show that there were about **3.66 million babies born** in the **U.S. last year**, a **decline** of **15% since 2007**, even though there are 9% more women in their prime childbearing years.

The decline has demographers puzzled and economists worried. America's longstanding geopolitical advantages, they say, are underpinned by a robust pool of young people. Without them, the U.S. economy will be weighed down by a worsening shortage of workers who can fill jobs and pay into programs like Social Security that care for the elderly. At the heart of the falling birthrate is a central question: Do American women simply want fewer children? Or are life circumstances impeding them from having the children that they desire?

The **gap between women's intended number of children** and their **actual family size** has **widened**.

New evidence points to the latter explanation. In a **study** published in January in the journal Population and Development Review, sociologists Karen Benjamin Guzzo and Sarah R. Hayford found that when **millennials** (born 1981 to 1996) and the oldest members of Generation Z (starting in 1997) were surveyed in their late teens and early 20s, they said, **on average**, that they **wanted** to have **at least two children** – just a fraction less than members of Generation X and the youngest baby boomers when they were surveyed at the same age.

But the gap between women's intended number of children and their actual family size has widened considerably. The researchers found that by the time women born in the late 1980s were in their early 30s, they had given birth, on average, to about one child less than they planned. That is roughly double the size of the shortfall for women born two decades earlier, and it is likely too large to be erased by a spurt of childbearing in their late 30s.

These findings reflect a growing consensus among demographers that for many Americans, **economic and social obstacles** have become intractable deterrents to having children. Young adults can't afford to buy a house as nice as the one their parents raised them in or to pay for childcare while they are still repaying student loans. Many men lack the earning power to be providers, because blue-collar jobs don't pay as well and fewer men are employed. More women can't find a suitable partner because, with their own greater education and economic status, it's harder for them to find a man who measures up.

"People aren't able to have the kids that they want," said Guzzo. "There's a growing feeling that if you were to have kids, you really need to provide something for them. You have to do all these things to give your kids advantages because the world is really tough right now. In a world where social mobility is limited and there's a weak social safety net, I think a lot of people look around and say, 'Well, maybe not.'" Leticia Quiles, a 36-year-old unemployed administrative assistant who lives in West Haven, Conn., said that she and her husband, an ATM coordinator, talked about having two children before they got married a decade ago. "We had definitely planned on having children at some point, but because of the economy and the time that you need to put aside for children, it's not something we can do," she said. "We can barely take care of ourselves let alone take care of a child." Instead, Quiles helps to care for her nieces and nephews, babysitting them and taking them for outings like wall climbing. "I get my fill," she said.

Some young people say that by not having children, they're helping to solve other global problems. "To me it feels borderline unethical to even be having kids with the way the future is looking in terms of climate change and resource shortages and all of that," said Cara Pattullo, a 31-year-old urban and environmental planner who lives with her boyfriend in Chicago. Instead, she thinks that she might adopt or foster children when she gets older, or forego childrearing altogether.

To maintain current population levels, the total fertility rate—a snapshot of the average number of babies women have over their lifetime – must stay at a "replacement rate" of **2.1 children per woman**. In **2021**, the **U.S. rate was 1.66**. Had fertility rates stayed at their 2007 peak, the U.S. would now have 9.6 million more kids, according to Kenneth Johnson, senior demographer at the University of New Hampshire.

Federal agencies are treating the slump like a temporary downturn. The **Social Security Administration**'s board of trustees **projects** that the **total fertility rate** will **slowly climb to 2 by 2056** and **hold there** until the end of the century. **Yet** it's been **over a decade since** fertility rates reached **that level**.

Last year there **were 2.8 workers for every Social Security recipient**. That ratio is **projected** to **shrink to 2.2 by 2045**, roughly **two-thirds** what it was in **2000**. Some other developed countries are in a far deeper childbearing trough than the U.S. In South Korea, the total fertility rate hit a world record low of 0.84 in 2020 and has since sagged to 0.78. Italy's rate slid to 1.24 last year. China's population fell in 2022 for the first time in decades because its fertility rate as been far below the replacement rate for years. Its two-century reign as the world's **most populous country** is expected to end this year when **India** overtakes it, if it hasn't already. In a recent note to clients, Neil Howe, a demographer at Hedgeye Risk Management, pointed to a World Bank report showing that the 2020s could be a second consecutive " lost-decade" for global economic growth, in large part because of worsening demographics.

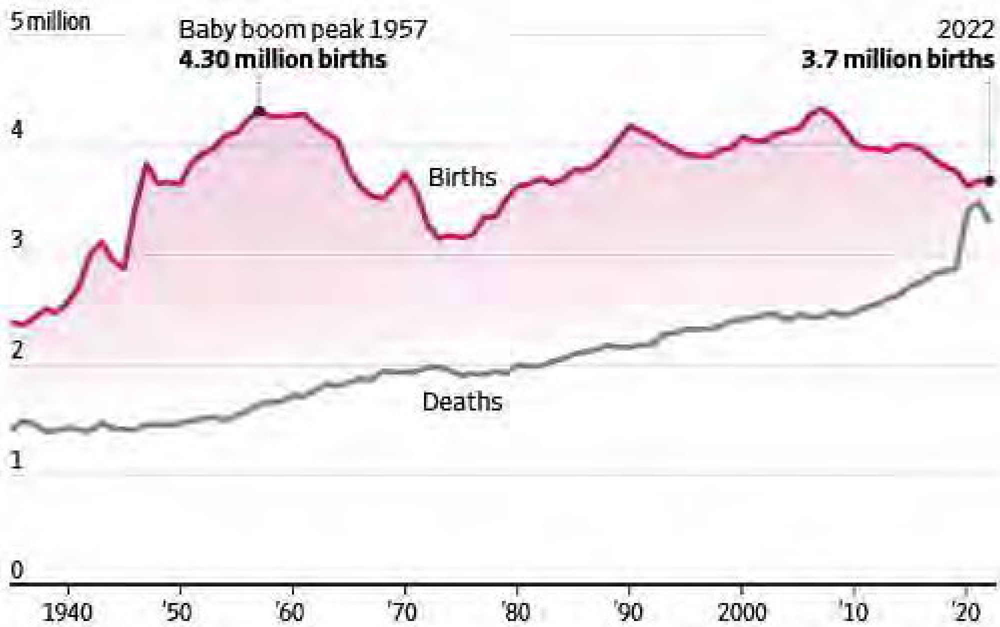
By 2026 or 2027, he wrote, the growth rate of the working-age population in the entire high-income and emerging-market world will turn from slightly positive to slightly negative, reversing a durable driver of economic growth since the Industrial Revolution. This shift will make the U.S. more dependent on immigration to supply enough workers to keep the economy humming. **Immigrants** accounted for **80% of U.S. population**

growth last year, census figures show, **up from 35%** just over a **decade ago**. Yet the **number of young immigrant women coming to** the **U.S. has diminished**, Johnson said, and the decline in fertility has been greatest among Hispanics. Having fewer children has already changed the social fabric of the country's schools, neighborhoods and churches. J.P. De Gance, president and founder of Communio, a nonprofit that helps churches encourage marriage, said that lower marriage and birth rates are one of the largest drivers of the decline in religious affiliation that's left pews empty across the country. That matters for the whole community, De Gance said, because churches give lonely people a place to form friendships, as well as feeding hungry people and running schools that fill gaps in public education. "When that's diminished, the entire culture's diminished," he said.

From Boom to Bust

The margin between U.S. births and deaths has narrowed dramatically since births peaked during the baby boom.

U.S. births, deaths by year



Note: 2022 data is provisional.
Source: Centers for Disease Control and Prevention

One reason the U.S. has fewer children is that the **teen birth rate** has **plunged 78% since** its **peak in 1991**. Greater access to contraception, including long-acting methods such as intrauterine devices, has helped curb unplanned pregnancies that prompt the youngest women to halt their education and become mothers before they're ready.

Whether the Supreme Court's 2022 Dobbs decision allowing states to prohibit abortion will materially lift the number of births is an open question. In 2017, the national abortion rate reached its lowest level since Roe v. Wade legalized the procedure in 1973, before drifting up over the next three years, according to data from the Guttmacher Institute, a policy group that supports abortion rights. There were about 930,000 abortions performed in the U.S. in 2020, the most recent year for which figures are available.

Kathryn Kost, Guttmacher's director of domestic research, said that new state-level restrictions on the procedure will make it harder to track abortions. "These laws push it underground," she said. In a recent paper, Kost and co-authors found that between 2009 and 2015, there was a drop in the rates of women who said they got pregnant too soon. At the same time, older women saw an uptick in pregnancies they described as happening later than they desired.

The median age at which women give birth is 30, three years older than it was in 1990. Despite advances in fertility treatments, women who delay having kids until their final childbearing years reduce their chances of doing so – not just because it narrows their biological window but because other priorities and roadblocks can more easily derail their plans.

"Right now I think we're one and done," said Hester Graves, a 42-year-old math researcher at a think tank who lives outside Washington, D.C. After giving birth to her daughter four years ago, she hemorrhaged and had to undergo surgeries and blood transfusions: "I would love to have a second. I don't know that I can risk my life to have a second."

U.S. policymakers are looking for solutions to the falling birth rate. President Joe Biden has proposed a series of measures aimed at aiding parents, including paid family leave, subsidized child care and federally funded preschool, though they've stalled amid opposition from lawmakers who say they're too expensive. Former president Donald Trump, who is trying to return to the White House in 2024, recently said that he supports paying out " baby bonuses" to fuel a reproductive boom.

Demographers say that it takes years of large-scale programs to spur childbearing. France, which has one of the highest fertility rates in the developed world, has long invested in pro-natalist policies including subsidized child care. Other countries are catching up. Hungary recently exempted women under the age of 30 who have a child from paying personal income tax.

Pilar Muner, a 34-year-old married human resources executive at a tech company, said that her desire to have children has run up against a series of deterrents, including long Covid. She doesn't want to waltz into parenthood like her mother and father's generation did: "You had more kids than you could afford. You smoked cigarettes when you were pregnant. Not a lot of thought went into it," said Muner, who lives outside Boston. "I think I'm just not ready."

For now, she is exploring freezing her eggs. "I have a lot of things I enjoy that have made me really happy," she said. "I don't want to feel like parts of my life are being compromised."

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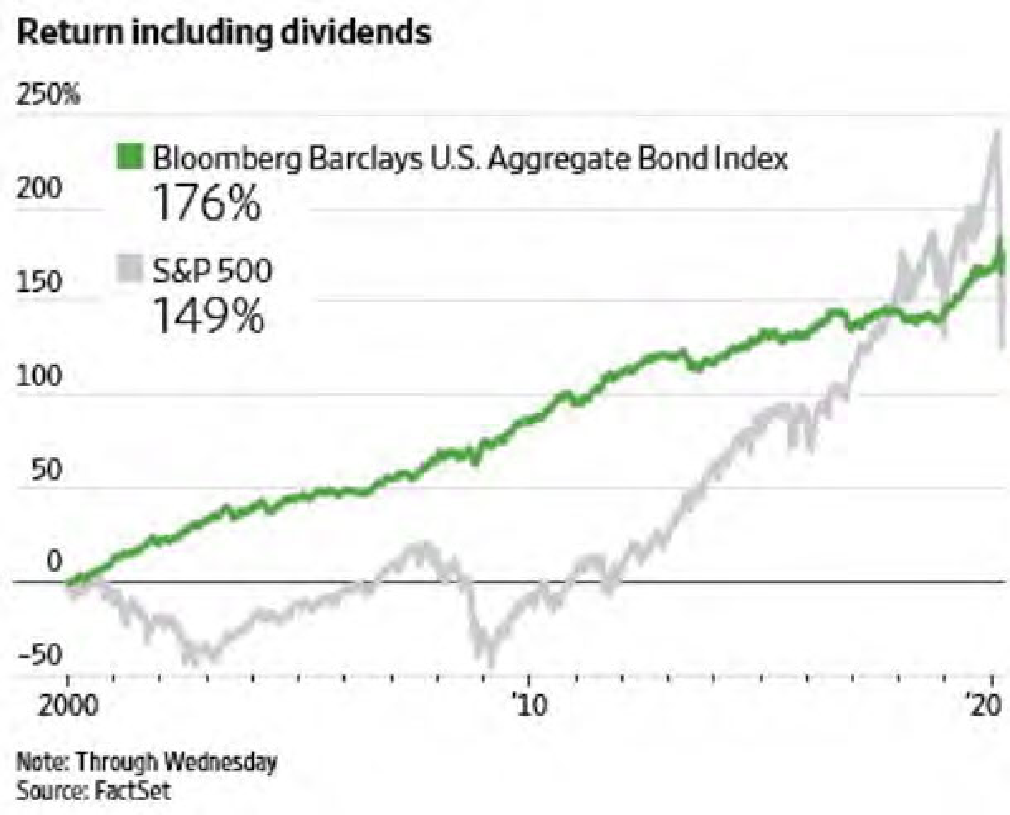
Bonds Outperform in the Battle of Returns

by Caitlin McCabe – WSJ – Apr. 3, 2020



Bonds have pulled away from stocks in the race for returns since the turn of the century.

Since the **close** of trading on **Dec. 31, 1999**, the Bloomberg Barclays **U.S.** Aggregate **Bond** Index, known as the Agg, has **netted investors** a **cumulative total return of 176% through Wednesday**, according to Fact-Set.

The **benchmark S& P 500 stock index, in contrast,** has **risen 149% in** the **century to date on** a **total-return basis, which reflects price gains plus periodic payments such as interest and dividends**. While the S& P gained about 2% Thursday, that wouldn't be enough to close its 21st-Century gap with bonds.

The outperformance of the Bloomberg Barclays index, considered the leading bond-market investment benchmark, underscores the extent of the recent carnage in stocks. **The S&P 500 suffered** its **fastest-ever fall from** a **record to** a **bear market last month** as **concerns** over the economic fallout from the **new coronavirus** swelled. The **index** is now **down 25% from** its **Feb. 19 high**. **Declines some days** have been **so sharp** that **rarely used circuit breakers** have **halted trading across** the **entire market**.

Bond prices, on the other hand, have **surged** as **investors scramble for haven assets**. Investors have poured record sums into bond funds in recent weeks, while continuing to pull money from stocks, Bank of America data show. The **yield** on the 10-**year U.S. Treasury note**, which moves inversely to prices, **recently plummeted** to a **record low**.

"I've been hearing for decades how returns in bonds can't continue to be positive because of low interest rates," said Kathy Jones, chief fixed-income strategist at the Schwab Center for Financial Research. "But the truth is they just keep delivering positive returns."

"Not only is [this] a **good eye opener** that **bonds** have **delivered better returns**, but they have also done so **with lower volatility**," she added.

The **coronavirus pandemic** has turned life upside down in the U.S., where **states** are **on lockdown** and **millions** of **Americans** have been **ordered** to **stay home**. **Jobless claims** have **soared** and **factories** have **slashed output**. **Goldman** Sachs Group Inc. this week issued new **estimates** that the **U.S. economy could shrink** an **annualized 34%** in the **second quarter** – far more severely than its estimate only weeks ago.

The projections mark a contrast from **just months ago** when **economic growth was expected** to **pick up** and **analysts projected** the **long-running bull market had more room to continue**.

This time last year, the **S& P 500 had returned** a **cumulative 183% since** the **start** of the **century**. **Meanwhile**, the benchmark **bond** index, which tracks government debt, mortgage debt and corporate debt, among other securities, **returned 152% to investors**.

To be sure, greater returns from stock indexes have still been possible lately: The Nasdaq Composite, as of Wednesday, returned 377% since September 2003, when total return data for the index became available, according to FactSet. The Dow Jones Industrial Average has also fared better than the bond index in the century to date, offering returns of nearly 196%.

A flight from stocks isn't atypical during times of crisis as investors try to minimize their risk. The Bloomberg Barclays **bond** index **outperformed** the **S& P 500 over various trailing periods during** the **financial crisis and other periods since 2000**.

"If you go back through time…I would say, yeah, typically, the Agg will deliver positive returns," Ms. Jones said. "Anytime we get into a stock market that has hit a major decline… you would probably find that is still the same trend."

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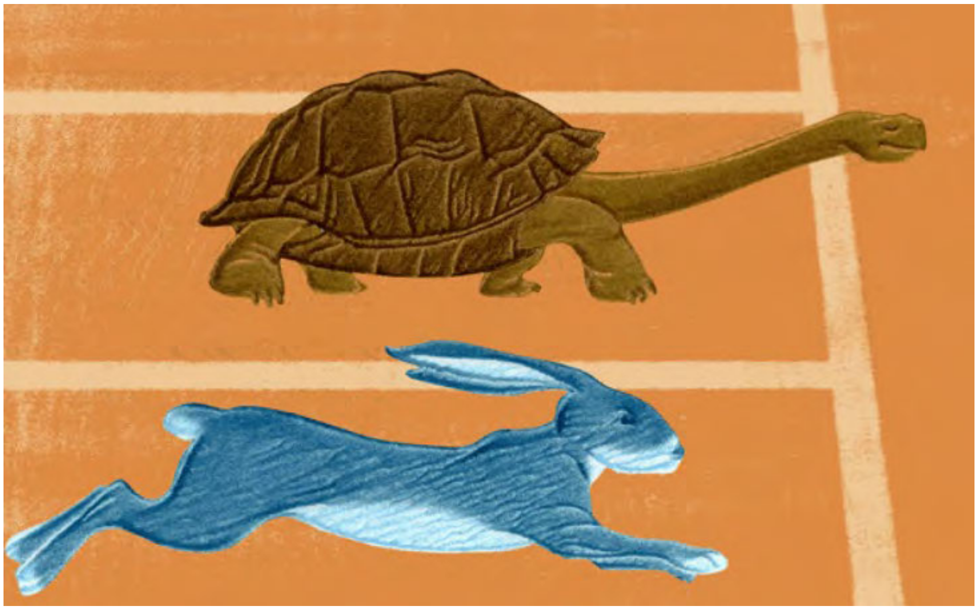
Sometimes, It's Bonds for the Long Run

by Jason Zweig, Intelligent Investor Column – WSJ – Nov. 2, 2018

When measured in three-decade increments, bonds did better than stocks as recently as 2011.



Maybe investors should **question** the **dogma** of "**stocks for the long run**." History shows that **a portfolio of bonds has outperformed stocks surprisingly often and for shockingly long periods**.

That's the intriguing argument in a **new research paper by Edward McQuarrie**, a **retired business professor at Santa Clara University**. Investors have long taken it as an article of faith that stocks have always beaten bonds – and always will – if you can just hang on long enough. Prof. McQuarrie's research is a **healthy reminder** that this **belief is wrong**. His findings also show the **limits and dangers of extrapolating from** the **past**.

Stocks offer a stake in a business's variable profits in the indefinite future. **Bonds are contracts conferring rights to a fixed stream of income over a certain period**. If stocks didn't offer the prospect of higher return, investors wouldn't want to brave the uncertainty of owning them. But **whether stocks deliver** that **higher return depends** largely **on** how they are **price**d **relative to bonds**.

The popular belief that there's never been a 30-year period in which stocks had lower returns than bonds is false. As recently as **2011**, **bonds had earned higher returns than stocks over** the **prior 30 years** (**long-term Treasury bonds, 10.7% annually**; **U.S. stocks, 10.4%**).

Bonds have **underperformed** **stocks** for **most of history**, **but not always.** New measures suggest the **long-term advantage of stocks** may be **weaker than many investors think**.

That's no aberration, says Prof. McQuarrie. Using digitized antique newspapers to supplement an online database of U.S. stock and bond prices, he assembled an index of bonds back to 1793.

That has enabled him to calculate 30-year returns beginning in 1823. Between then and 2013, he shows, **bonds earned higher returns than stocks in one-quarter of all 191 three-decade-long periods**.

Most of those stretches were in the 19th century. But much of the data on which **Jeremy Siegel**, a finance professor at the University of Pennsylvania's Wharton School, relied for his best-selling 1994 book "Stocks for the Long Run" also came from the same era.

The **difference**: **Prof. McQuarrie constructed his early data with a wide variety of bonds that would have been available to investors at the time**. **Prof. Siegel chose the highest-quality and lowest-yielding bonds available** – often a single U.S. Treasury bond or as few as two municipal bonds.

According to Prof. McQuarrie, the issues tracked in "Stocks for the Long Run" account for less than 5% of the total bond market in much of the 19th century.

Prof. Siegel used so **small** a **sample** in order **to approximate** what economists call the "**risk-free rate**," or the return on a bond with the lowest possible danger of defaulting.

In **academic theory**, that **makes perfect sense**. **In** the **real world**, the **early U.S**. **had no risk-free rate**. Not only was the **survival of** the **nation often in doubt**, but **from 1835 through 1841** the **U.S. Treasury didn't even have any debt outstanding**. **By** the **1840s eight states had defaulted**. **Most bonds were risky**, so they **often had to offer yields of 5% or more**.

Seen through that wider lens, says Prof. McQuarrie, stocks don't overwhelmingly dominate bonds. "**Sometimes bonds give you a better return; sometimes, stocks do**." Calculations of bond returns based on only a sliver of the market are a "heroic extrapolation," he says.

That the bonds in "Stocks for the Long Run" might have been "a tiny part of the market does not bother me," says Prof. Siegel. He points out that three-month Treasury bills, often used as today's risk-free rate, are also a small fraction of the market.

Could bonds as a whole – as opposed to a handful of high-quality issues – have done better than stocks in the early U.S.?

"That's **possible**, and it might be in the data," **says Prof. Siegel**. "Clearly, in that early period, with bonds that had higher yields, it could well be that the broad bond market may have outperformed stocks."

Prof. McQuarrie calculates that bonds did slightly better than stocks – an average of 5.9% annually versus 5.8%, after inflation – all the way from the beginning of 1793 through the end of 1877.

To come out ahead of bonds back then, you would have had to hold stocks continually for more than 85 years – probably a tad longer than what most investors have in mind when they think of the phrase "stocks for the long run."

Are these returns from the days of steamboats and stovepipe hats relevant today?

The **pattern identified by Prof. McQuarrie has held in** several countries in the modern era. In **France**, **Italy**, **Japan** and Spain, among other nations, **bonds have earned better returns than stocks** – **after inflation**—**for decades on end** in the post-1900 era.

"Is it **likely** that **stocks will outperform bonds**?" asks **Prof. Siegel**. "**Of course**. **But** should we never **expect** to **find periods when bonds outperform stocks**? No, no, no. We should expect to find that, absolutely."

No one should ever assume that the outperformance of stocks over bonds, even over extremely long periods, **is** "**predestined or foreordained**," he says. That's especially true when interest rates start at high levels.

Many investors have put blind faith in stocks, confident that history will repeat itself. **Someday it might** – in a way that investors who have all their money in stocks should hedge against before it's too late.

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Will Stocks Trail Bonds Over the Next Decade?

by Mark Hulbert – WSJ – Jun. 8, 2020

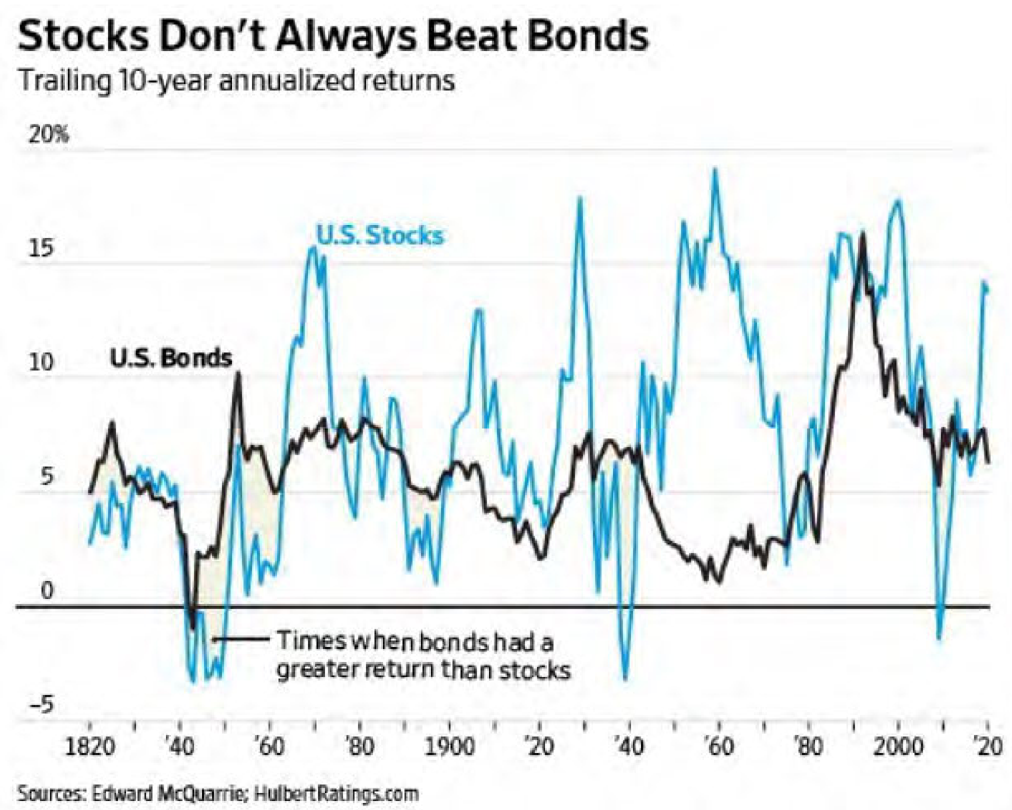
It would startle investors, but a new analysis suggests there is a decent chance that will happen. Conversely, market historian Jeremy Siegel says that stocks will still easily beat bonds in the next decade.

The **conventional wisdom** among investors hasn't changed for years: **Stocks beat bonds in** the **long run**.

This is still a bedrock principle for many, even after the coronavirus lockdowns sent stocks, and the spectacular bull market of recent years, tumbling. Indeed, stocks rebounded with startling speed, launching a new bull market in the process. And looking ahead, some see little reason to believe that stocks will lose their historic edge over bonds. The bar right now is particularly low: **Currently**, the **Moody's Seasoned Aaa Corporate Bond Yield** is just **2.5%**, and stocks continue to show their resilience.

The **S&P 500 yields** almost as much – **1.8%** – and, **unlike bonds**, **equities** have the **potential** to **appreciate** as the economy recovers and corporate earnings rebound.

However, a **prominent dissenting voice** has emerged, and he, too, claims to have history on his side. **Edward McQuarrie**, a **professor** emeritus at the **Leavey School** of **Business** at **Santa Clara University**, has spent years reconstructing the history of stock and bond returns, extending practically to the birth of the country. And he **puts** the **odds** that **U.S. stocks** will **underperform investment-grade bonds over** the **next decade** at a **surprising 4 in 10**.



Most investors will be dismayed by those odds. A decade, after all, ought to be long enough for stocks to assert their historical dominance over bonds, But Prof. **McQuarrie's analysis** is based on close study of **stock** and **bond** returns **going back to 1793**. And he has found that **bonds outperformed stocks** in **38.7% of all 10-year periods since then**. (See accompanying chart.

Prof. McQuarrie furthermore has **found** that, in **many additional 10-year periods**, **bonds lagged behind stocks by less than** an **annualized percentage point**. Investors then presumably felt that stocks didn't offer enough compensation in return for the greater volatility and risk. **If you count all 10-year periods** in which **bonds either beat stocks or trailed by less than an annualized percentage point, bonds held** their **own 51% of** the **time since 1793**.

But wait a minute:

Not all market historians agree with Prof. McQuarrie's calculation of these odds. One is **Jeremy Siegel**, a **finance professor** at the **Wharton School** of the **University of Pennsylvania**. In the most recent edition of his **classic**, "**Stocks for** the **Long Run**," he reports that **bonds beat stocks** in **just 27.9%** of **all 10-year holding periods since 1802**. In an email, Prof. **Siegel** expresses **confidence** that the **next decade** will be one in which **stocks easily beat bonds**.

There are **several reasons** why these **two researchers calculate** the **odds** to be **significantly different**. One is that the **bond market** in the **19th century** was **far less developed**. During **some stretches**, in fact, **no Treasury bonds** even existed.

Prof. **Siegel** reports that he **overcame gaps** in the **historical record** by looking at a **combination** of **yields** on **federal** and **municipal bonds**, an approach that he believes most closely **approximates** what the **risk-free rate** of **return** was in the **19th century**. Prof. **McQuarrie's** approach was to **focus** on **investment**-**grade bonds** with **long maturities**, **whether federal**, **muni** or **corporate**, since all three were actively traded, and all suffer from gaps in the record. The **consequence** is that Prof. **McQuarrie shows bonds** to have **performed significantly better** in the **19th century than does** Prof. **Siegel**.

The long view:

If Prof. McQuarrie is right about bond-market returns in the 19th century, then we also need to temper our confidence that, so long as we hold on long enough, stocks will come out on top. That is the basis of the nearly universal financial-planning advice that investors with long-term horizons should allocate the bulk of their portfolios to equities.

Prof. **Siegel's data** famously provides support for this belief: **Based** on **all 30-year holding periods since 1802**, the **odds** of **stocks beating bonds** are **more than 91%—compared with 72% for 10-year periods.**

Prof. **McQuarrie's data**, **in contrast**, shows that **stocks' odds** of **beating bonds** are **barely higher** at the **30-year horizon than** at the **10-year horizon**— **65.5% versus 61.3%**.

In an interview, Prof. **McQuarrie** says that his **research** found "**little support** for the **comforting thesis** that the **longer you hold stocks**, the **more likely** you are to **enjoy** a **stronger return than bonds**."

Interest rates and stocks:

Given **today's rock-bottom interest rates**, a long-term bet on stocks over bonds might still make sense. Consider the period beginning in 1940, during which stocks beat bonds by the most they have over any sustained period since 1793. The 10-year Treasury yield in 1940 was below 2%, lower than at any other time in U.S. history except recently. When rates rose, bonds lost value and stocks opened up a big lead.

Wouldn't the same be true for coming years? Prof. **Siegel** thinks so. He says **stocks** will **outperform bonds** over the **next decade** by an **annualized margin** of **between 5 and 6 percentage points** – exceeding the average premium over 200 years.

Entering **another dissenting voice**: **Rob Arnott**, chairman of investment firm **Research Affiliates**. One reason for his skepticism, he says, is the **low correlation** between a **given year's bond yield** and the **stock market's subsequent 10-year return**.

To show this, Mr. **Arnott calculates** a statistic known as the **r-squared**, which would be **100% if** a **decade's initial bond yield completely explained stocks' subsequent 10-year return**, and **0%** if that bond yield had **no explanatory power**. **For all 10-year periods since** the **beginning** of the **19th century**, according to Mr. Arnott, the **r-squared** was **just 3%** – "pretty lame," he says.

An indicator with far higher forecasting power for stocks' 10-year returns, he says, is the **cyclically adjusted price/earnings ratio** (or **CAPE**) that was made famous by **Yale finance professor** and **Nobel laureate Robert Shiller**. Mr. **Arnott calculates** that, for **all 10-year periods since 1881**, the first year for which CAPE data is available, the **r-squared** is **over 50%.**

This finding **cancels out** any **argument** that, **based on today's low interest rates**, **stocks will handily beat bonds for** the **next decade**. That's because the **CAPE shows** the **stock market today** to be **more overvalued than in 92%** of the **time** since **1881** – 27.6, versus a long-term average of 17.0.

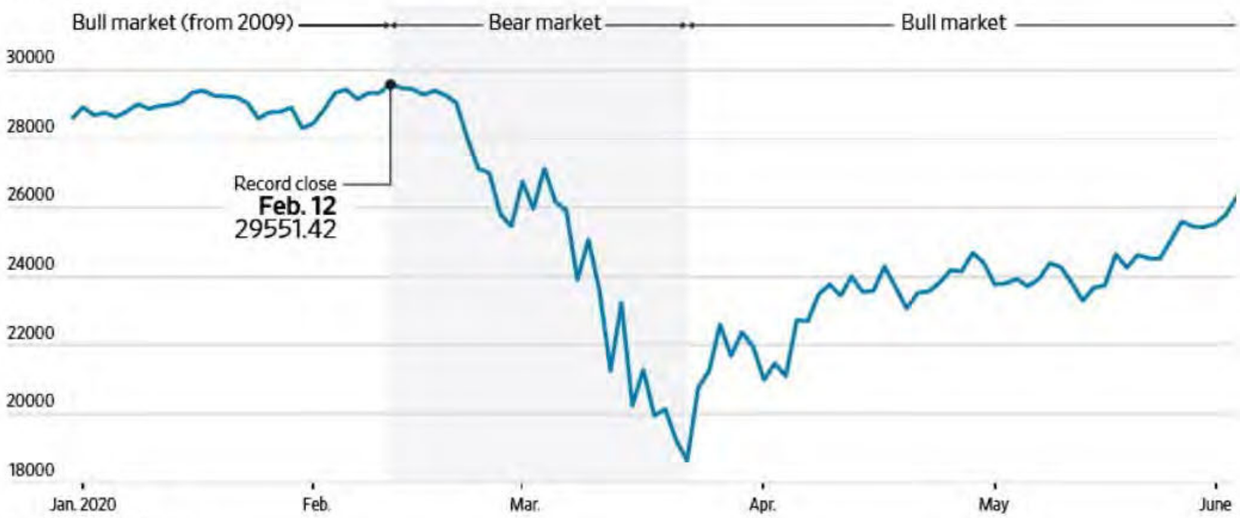
This finding also puts in a different light the **period beginning** in 1940 in which **stocks dramatically beat bonds**. The **CAPE in 1940** was barely **half** where it is **today**, **indicating** a **significantly undervalued market**. It provides a better explanation than low rates for why stocks did so much better than bonds in subsequent years.

Because of this and other considerations, Mr. **Arnott** is **forecasting** that **U.S. stocks will outperform** the **U.S. bond market** by an **annualized margin** of **just 1.3 percentage points over** the **next decade**.

One for the History Books

U.S. stocks this year have startled investors with the lockdowns-triggered slides into a bear market, followed by a sudden return to a bull market (defined as having had a 20%-plus recovery from the low).

Dow Jones Industrial Average



Source: Dow Jones Market Data

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S&P Global

Major energy rate case decisions in the US

January-June 2023

Quarterly update on decided rate cases

Lisa Fontanella, **Research Director**

Contributors: Brian Collins, Jim Davis, Russell Ernst, Lillian Federico, Monica Hlinka, Jason Lehmann, Dan Lowrey

Editor: Wyatt Scott

For detailed data

Access the RRA's electric and gas rate case decisions as of June 30, 2023, data tables.

Averages calculated for the first half of 2023 show that electric and gas authorized returns on equity are modestly trending higher.

To learn more or to request a demo, visit spglobal.com/marketintelligence.

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Executive Summary

Introduction

The average electric and gas authorized returns on equity are modestly trending upward.

The average return on equity authorized electric utilities was 9.56% in rate cases decided in the first half of 2023, modestly above the 9.54% average for full year 2022. There were 21 electric ROE authorizations in the first half of 2023 versus 53 in full year 2022.

The average ROE authorized gas utilities was 9.66% in cases decided in the first half of 2023 versus 9.53% in full year 2022. There were 10 gas cases that included an ROE determination in the first half of 2023 versus 33 in full year 2022.

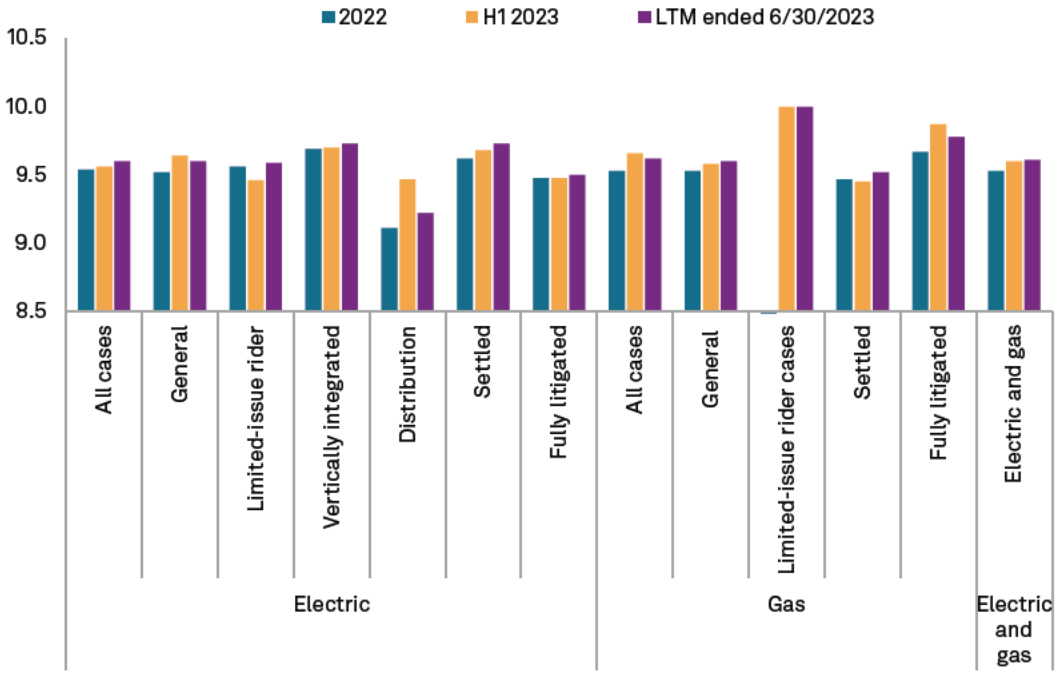
Rate case activity remained elevated in 2022, with state public utility commissions issuing about 136 decisions. That level of activity, however, was down from 2021 — a record year with 151 decisions rendered in electric and gas rate cases across the US.

While the reasons for a rate case filing are numerous, the main driver continues to be the recovery of capital expenditures. Energy utilities are investing in infrastructure to modernize transmission and distribution systems; build new natural gas, solar and wind generation; and deploy new technologies to accommodate the expansion of electric vehicles, battery storage and advanced metering infrastructure that facilitate the transition toward decarbonization. Other reasons for rate filings include rising expenses, revised cost of capital parameters, the impact of broader economic and sector-wide forces on operations, the need to address rate treatment to be accorded generation facilities that are being retired prior to the end of their planned service lives due to the energy transition, recovery of storm and severe-weather related costs and regulatory approval for alternative regulatory mechanisms.

About this report

This quarterly report offers a detailed overview of electric and gas rate case decisions issued in the US during the first half of 2023 and select aggregated historical data. The information presented in this report utilizes the data compiled by Regulatory Research Associates for its rate case database, available on the S&P Capital IQ Pro platform. RRA endeavors to follow all “major” rate cases for investor-owned utilities nationwide, with “major” defined as a case in which the utility’s request would result in a rate change of at least $5 million or in which the commission approves a rate change of at least $3 million. In addition to base rate cases, the rate case history database includes details regarding certain limited-issue rider proceedings, primarily those involving significant rate base additions recognized outside of a general rate case. In some of these cases, the rate change coverage criteria may not apply. Historical data in this report may not match earlier data provided in previous reports due to differences in presentation, including the treatment of withdrawn or dismissed cases and the addition of cases not previously included in RRA’s coverage.

Average authorized ROE (%)



	2022	H1 2023	LTM ended 06/30/23
Electric averages			
All cases	9.54	9.56	9.60
General rate cases	9.52	9.64	9.60
Limited-issue rider cases	9.56	9.46	9.59
Vertically integrated cases	9.69	9.70	9.73
Distribution cases	9.11	9.47	9.22
Settled cases	9.62	9.68	9.73
Fully litigated cases	9.48	9.48	9.50
Gas averages			
All cases	9.53	9.66	9.62
General rate cases	9.53	9.58	9.60
Limited-issue rider cases	--	10.00	10.00
Settled cases	9.47	9.45	9.52
Fully litigated cases	9.67	9.87	9.78
Composite electric and gas averages			
Electric and gas	9.53	9.60	9.61
US Treasury			
30-year bond yield	3.11	3.78	3.67

Data compiled July 26, 2023.
ROE = return on equity; LTM = last 12 months.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; U.S. Department of the Treasury.

The Take

Averages calculated for the first half of 2023 show that electric and gas authorized returns on equity are modestly trending higher. In recent years, rate case activity for investor-owned electric and gas utilities in the US has been elevated, with state public utility commissions issuing about 136 decisions in 2022. This level of activity, however, is down from 2021, which was a record year with 151 decisions rendered in electric and gas rate cases across the US. With rising interest rates, RRA anticipates rate case filings will remain robust.

For full year 2023, average authorized returns may edge slightly higher than the annual levels observed in 2022, as higher interest rates resulting from the US Federal Reserve's anti-inflation tightening policies will likely begin impacting authorized ROEs. However, the effect of interest rate increases on authorized returns will likely be limited given that regulators are slower to adjust ROEs upwards than downwards, and affordability concerns persist as regulators contend with customer rate increases stemming from significant but necessary capital investment in the energy transition during a period of high inflation.

Overview of electric and gas authorizations

The average electric and gas authorized returns on equity edged modestly higher per averages calculated for the first half of 2023.

The average ROE authorized for electric utilities was 9.56% for rate cases decided in the first half of 2023, above the 9.54% average observed in full year 2022. There were 21 electric ROE determinations reflected in the calculations for the first half of 2023 versus 53 in full year 2022.

The average ROE authorized for gas utilities was 9.66% for cases decided in the first half of 2023, above the 9.53% average observed in 2022. There were 10 gas rate case decisions decided in the first half of 2023 versus 33 in full year 2022.

The electric data set includes several limited-issue rider cases. Historically, the ROEs authorized in limited-issue rider cases were meaningfully higher than those approved in general rate cases, driven primarily by incentives allowed in Virginia for certain types of generation investment. These premiums have largely expired, however, narrowing the gap between the average ROE in the rider cases and general rate cases. Excluding rider cases, the average authorized ROE for electric cases was 9.64% in the first half of 2023 versus 9.52% in full year 2022.

Excluding the two rider cases, the average authorized ROE for gas cases was 9.58% in the first half of 2023. There were no rider cases with a gas authorized ROE in 2022. For the most part, limited issue riders have a limited impact on average ROEs in the gas sector, as most of the gas riders rely on ROEs approved in a previous base rate case.

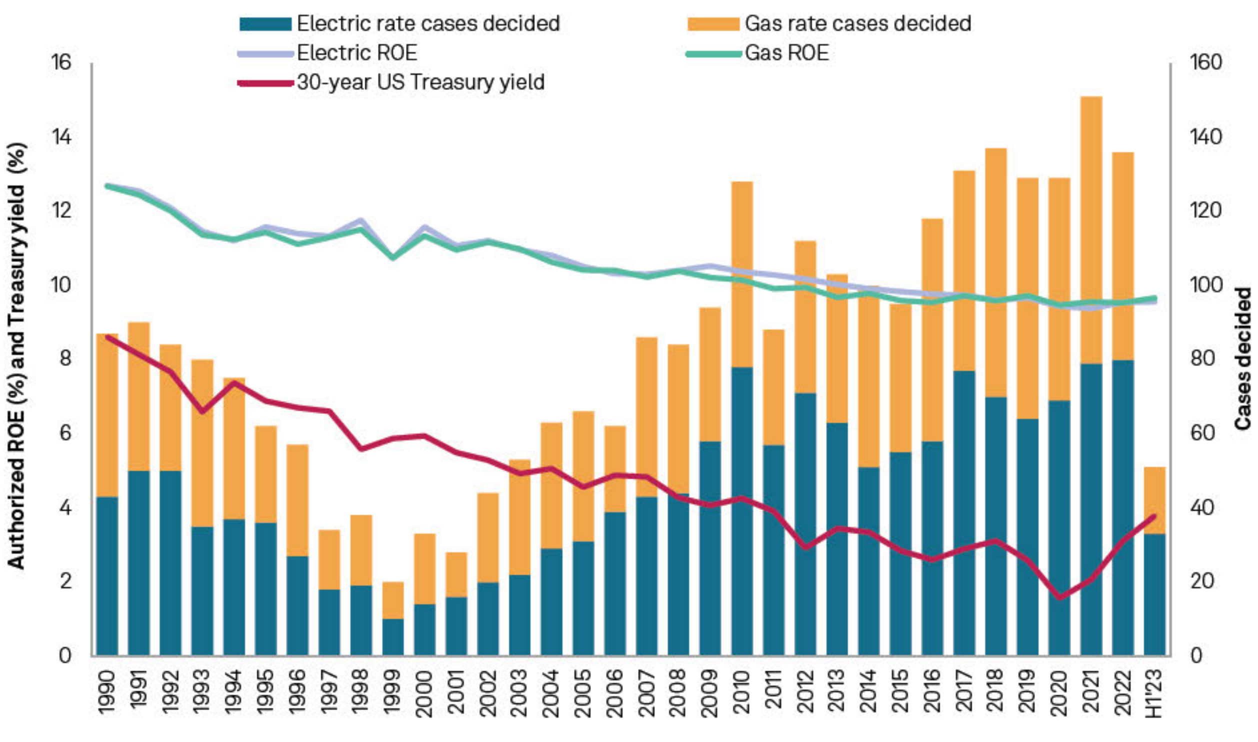
In the first half of 2023, the median ROE authorized in all electric utility rate cases was 9.35%, versus 9.50% in full year 2022; for gas utilities, the metric was 9.56% in the first half of 2023 and 9.60% in full year 2022.

Looking at the last 12 months ended June 30, 2023, the average ROE authorized in all electric utility rate cases was 9.60%, and the median was 9.60%. For gas utilities in the last 12 months ended June 30, 2023, the average was 9.62%, and the median was 9.60%.

The full-year averages in recent years are at the lowest levels ever witnessed in the industry. ROE determinations in Illinois and Vermont calculated using a formulaic approach tied to US Treasury bond yields weighed down the electric ROE average in 2022. Excluding these ROE determinations, the average return authorized for electric utilities was 9.63% in 2022.

Looking longer-term, interest rates — as measured by the 30-year US Treasury bond yield — fell almost steadily between 1990 and 2020, placing downward pressure on authorized ROEs; however, the decline in authorized ROEs was much less dramatic than that for Treasury yields. Between 1990 and 2020, Treasury yields fell more than 700 basis points, to 1.56% from 8.61%, while average authorized ROEs for electric and gas utilities combined fell less than 325 basis points, to 9.45% from 12.69%. The average authorized ROEs did not fall below 10% until 2011 for gas utilities and until 2014 for electric utilities. The calendar-year averages fell below 9.50% for the first time in 2020.

Average electric, gas authorized ROEs; number of rate cases decided



Data compiled July 26, 2023.
ROE = return on equity.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; US Department of the Treasury.

The decline in authorized ROEs has coincided with an upswing in rate case activity, with 100 or more cases adjudicated in 10 of the last 12 calendar years. This count includes electric and gas cases where no ROEs were specified, but it does not include withdrawn cases. At over 150 cases, rate case activity in 2021 was the most robust observed in any year during the 1990-2022 period. In 2022, 136 cases were decided.

Absent the pandemic, increased costs associated with environmental compliance, generation and delivery infrastructure upgrades and expansion, renewable generation mandates, storm and disaster recovery, cybersecurity, early plant retirement and employee benefits have contributed to an active rate case agenda over the last decade.

Due to the COVID-19 pandemic and the challenging economic landscape, many utilities and state commissions sought to limit the immediate impact of rate hikes during 2020 by pushing rate changes into a future period or agreeing to forgo rate hikes and using accounting mechanisms, such as the accelerated recovery of excess accumulated deferred tax liabilities, to mitigate requested increases.

Amid the current high inflationary environment, the pace of rate case activity in the US is robust, with about 115 electric and gas rate cases currently pending.

With interest rates and authorized ROEs declining at different rates between 1990 and 2020, the spread between authorized ROEs and the average yield on 30-year US Treasuries somewhat widened over this period — from a little over 400 basis points in 1990 to peaking at just under 800 basis points in 2020.

This occurrence is attributable primarily to the regulators' often-unstated understanding that the drop in interest rates caused by the Fed intervention was unusual. Consequently, regulators did not necessarily fully reflect the interest rate drop in newly authorized ROEs in some instances; in others, regulators acknowledged that the changing dynamics of the industry and instability in the overall economy presented increased risks for investors, justifying a higher premium over interest rates.

In 2021, the spread narrowed slightly as Treasury yields rose, and in 2022, the spread fell to below 650 basis points.

Nevertheless, with the uptick in interest rates, allowed returns may begin to edge slightly higher in 2023 as the Fed continues to raise interest rates as part of an aggressive effort to restrain inflation.

The effect of interest rate increases on authorized returns is unlikely to be dramatic, as authorized returns tend to be stickier on the upside than on the downside. In addition, affordability concerns will likely continue as regulators contend with inflationary pressures and stranded costs related to the energy transition. These considerations will be further complicated by several issues, including the overall macroeconomic picture and the record-high level of planned capital spending expected in the industry, particularly to fund the energy transition.

Capital structure trends

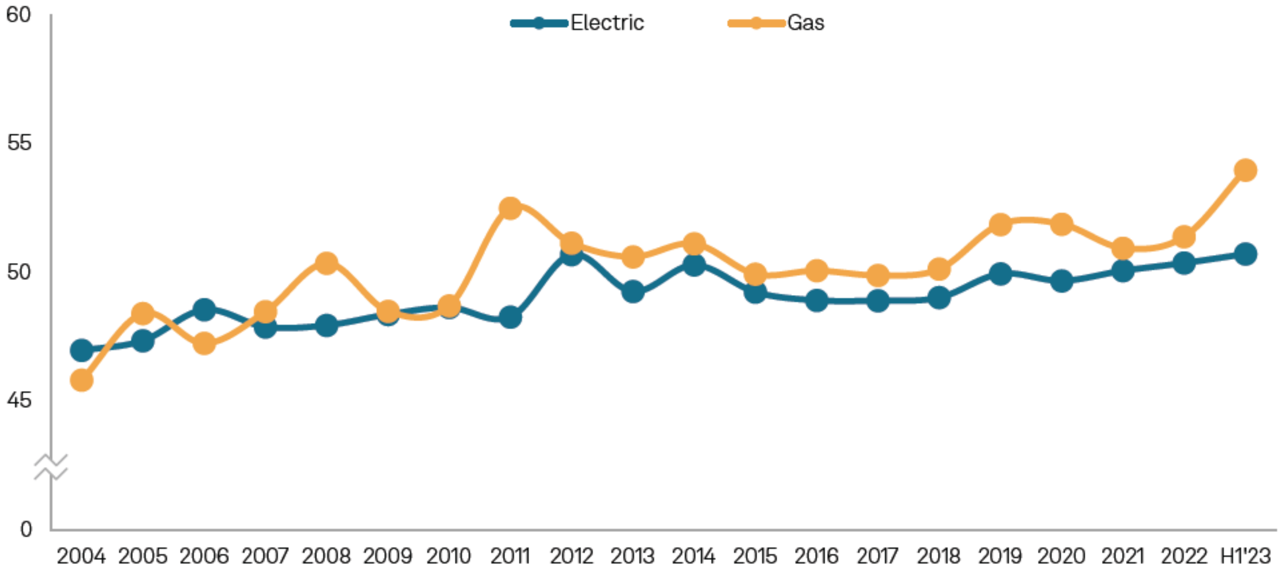
The negative cash flow impact of federal tax changes that took effect in 2018 raised concerns regarding utility liquidity and credit metrics. In response, many utilities sought higher common equity ratios, and the average authorized equity ratios adopted by utility commissions in 2019 were modestly higher than those observed in 2018 and 2017.

For full years 2022, 2021, 2020, 2019, and 2018, the average equity ratios authorized in electric utility cases were 50.36%, 50.06%, 49.67%, 49.94%, and 49.02%, respectively. The average equity ratios authorized gas utilities were 51.38%, 50.94%, 51.87%, 51.86%, and 50.12%, respectively.

In the first half of 2023, the average authorized equity ratio for electric utility cases nationwide was 50.71%. For gas utilities, the average authorized equity ratio nationwide was 53.97%.

Taking a longer-term view, equity ratios have generally increased over the last several years — the average equity ratio approved in electric rate cases decided during 2004 was 46.96%, while the average for gas utilities was 45.81%. Many commissions began approving more equity-rich capital structures in the wake of the 2008 financial crisis. For the bulk of the period since 2004, allowed equity ratios for gas utilities have been above those authorized for electric utilities.

Average authorized equity ratio (%)



Data compiled July 26, 2023.
ROE = return on equity.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; US Department of the Treasury.

A more granular look at ROE trends

Thus far, the discussion has looked broadly at trends in authorized ROEs; the following sections provide a more granular view.

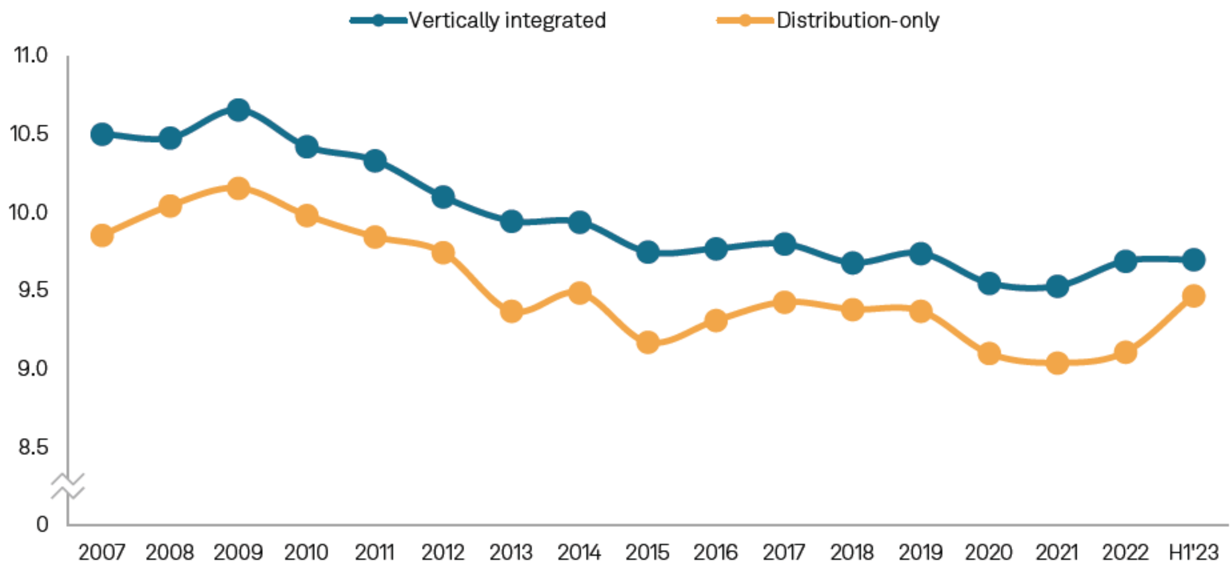
RRA has observed that there can be significant differences between average ROEs based on the types of proceedings/decisions in which these ROEs were established.

As a result of electric industry restructuring, certain states unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction only over the revenue requirement and return parameters for distribution operations.

RRA finds that the annual average authorized ROEs in vertically integrated cases involving generation have been about 30 to 65 basis points higher than in distribution-only cases, arguably reflecting the increased risk associated with the ownership and operation of generation assets.

The industry average ROE for vertically integrated electric utilities was 9.70% in cases decided in the first half of 2023 versus the 9.69% average in full year 2022. For electric distribution-only cases, the industry average ROE was 9.47% in the first half of 2023 versus the 9.11% average in full year 2022.

Average authorized electric ROEs (%)

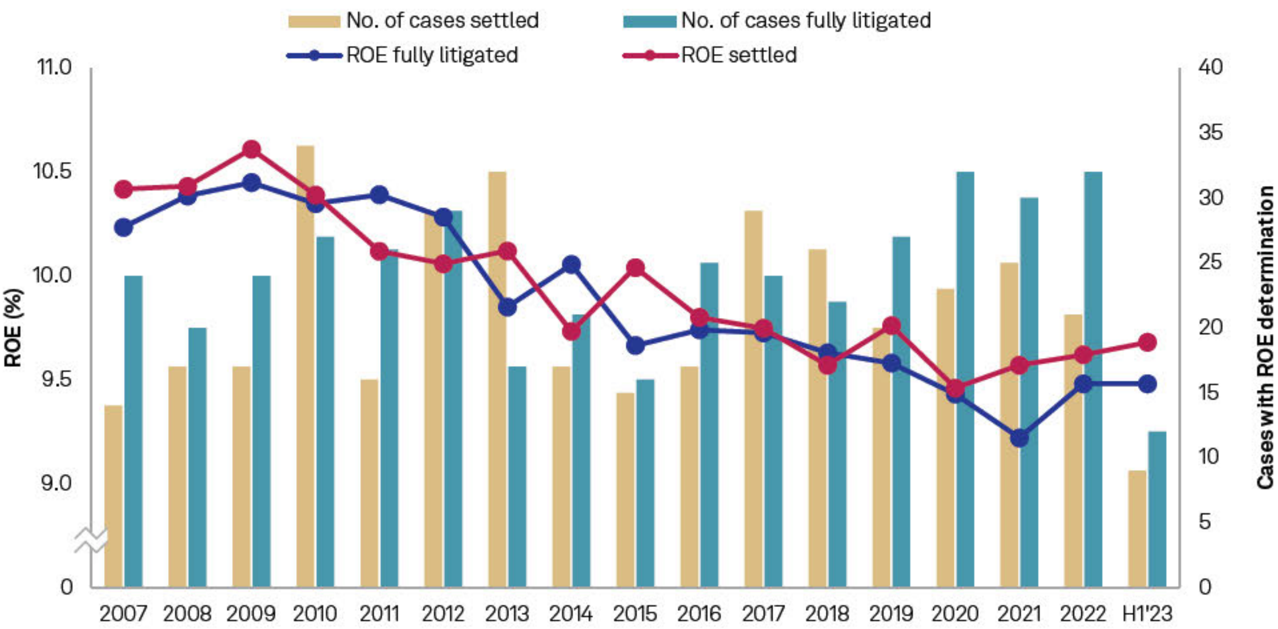


Data compiled July 26, 2023.
ROE = return on equity.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

Settlements have frequently been used to resolve rate cases over the last several years, and in many cases, these settlements are "black box" in nature and do not specify the ROE and other typical rate case parameters underlying the stipulated rate change. Some states, however, preclude this type of treatment, and settlements must specify these values, if not the specific adjustments from which these values were derived.

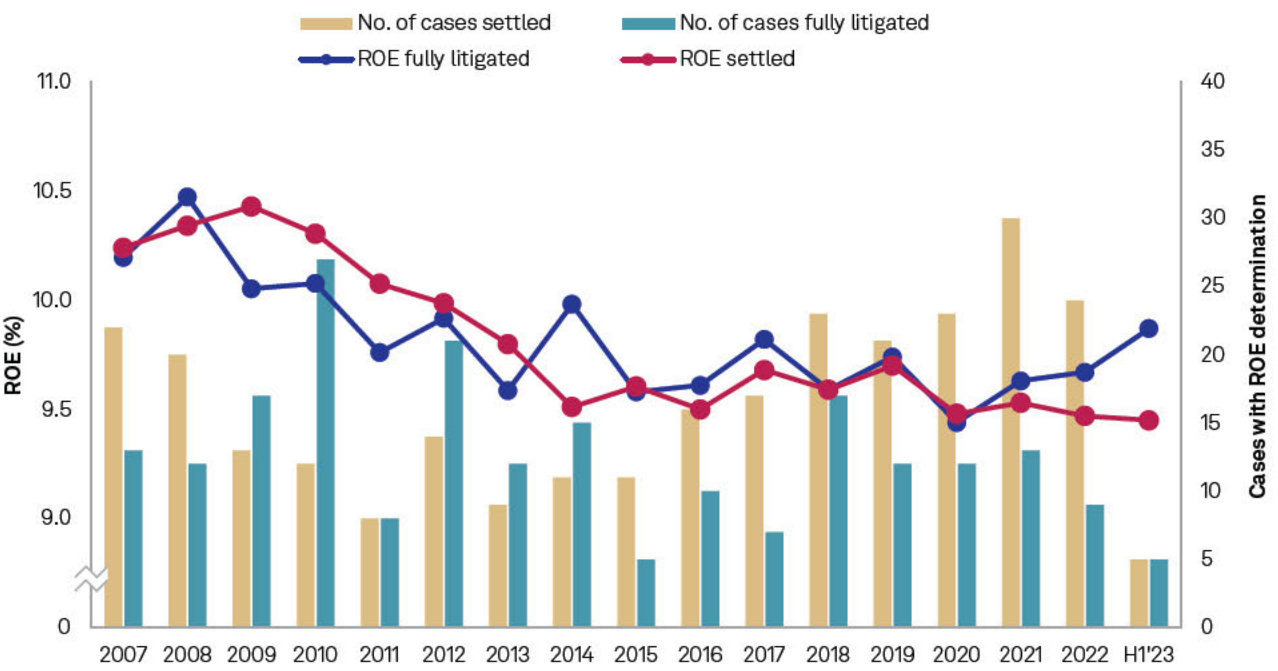
For both electric and gas cases, RRA has found no discernible pattern in the average authorized ROEs in cases that were settled versus those that were fully litigated. In some years, the average authorized ROE was higher for fully litigated cases, while in others, it was higher for settled cases.

Average authorized electric ROEs: settled vs. fully litigated cases



Data compiled July 26, 2023.
ROE = return on equity.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

Average authorized gas ROEs: settled vs. fully litigated cases



Data compiled July 26, 2023.
ROE = return on equity.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

The following discussion focuses on the corresponding tables available here.

Table 1 shows the average ROE authorized in major electric and gas rate decisions annually since 1990 and quarterly since 2018, followed by the number of observations in each period. Table 2 indicates the composite electric and gas industry data for all major cases, summarized annually since 2004 and quarterly since 2021.

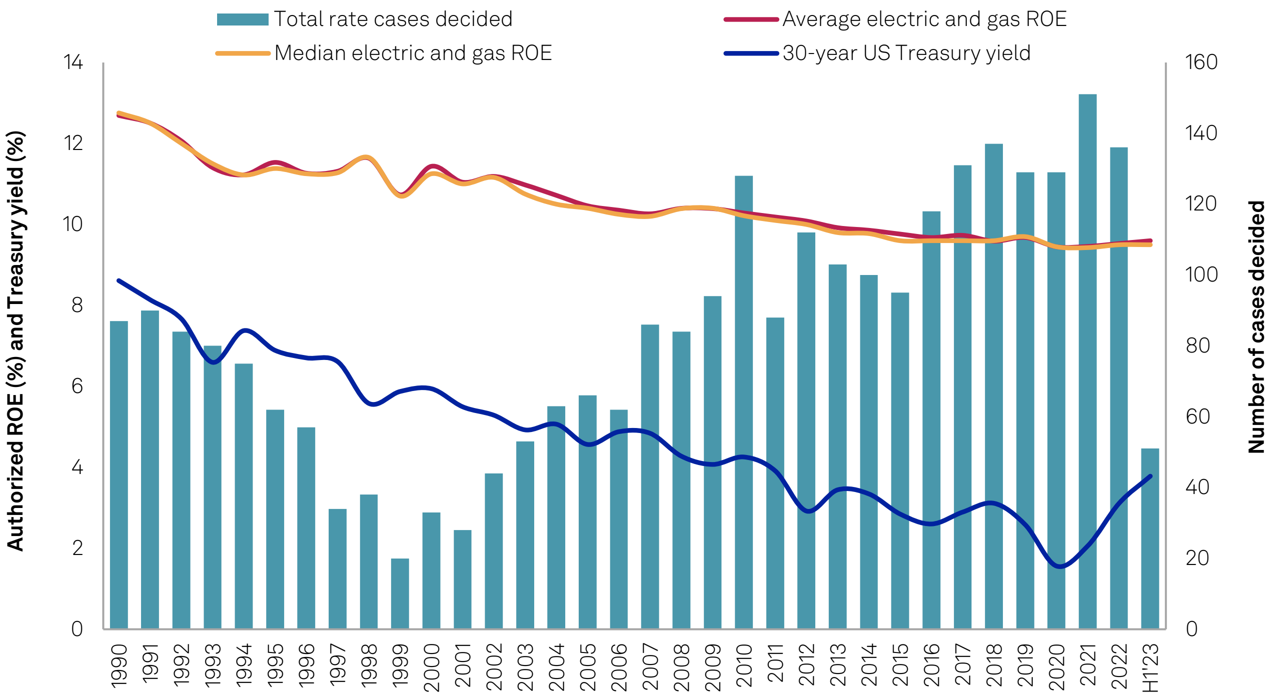
Tables 3 and 4 provide comparisons since 2007 of average authorized ROEs for settled versus fully litigated cases, general rate cases versus limited-issue rider proceedings and vertically integrated cases versus delivery-only cases for electric and gas utilities, respectively.

The individual electric and gas cases decided in the first half of 2023 are listed in **Table 5**, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return, the ROE and the percentage of common equity in the adopted capital structure. Next, RRA indicates the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time the decisions were rendered. Fuel adjustment clause rate changes are not reflected in this study.

The simple mean is utilized for the return averages. In addition, the average equity returns indicated in this report reflect the ROEs approved in cases decided during the specified time periods and are not necessarily representative of the average currently authorized ROEs for utilities industrywide or the returns earned by the utilities.

Table 6 and the graph below track the combined average and median equity return authorized for all electric and gas rate cases since 1990. As the table indicates, since 1990, authorized ROEs have generally trended downward, reflecting the significant decline in interest rates and capital costs over this time frame.

Composite electric, gas average authorized ROEs; total number of rate cases



Data compiled July 26, 2023.
ROE = return on equity.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; US Department of the Treasury.

Further Reading

[Intro to Water Utilities — Current Trends and Growth Drivers]

[Major utility cases in progress — Pending significant non-rate case activity]

[Rate base: It's more complicated than it sounds]

[FERC Regulatory Review]

[The rate case process: a conduit to enlightenment]

[Major Energy Utility Cases in Progress in the US - Quarterly Update on Pending Rate Cases]

[Rate base: How would you rate your knowledge of this utility industry fundamental?]

[Frequently Asked Questions]

[Adjustment Clauses — a State by State Overview]

[Adjustment Clauses — Data tables]

[The Commissions]

[Utility Asset Securitization in the U.S.]

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About Regulatory Research Associates

Regulatory Research Associates, a group within S&P Global Commodity Insights, is the leading authority on utility securities and regulation. Understanding the financial and strategic impact of federal and state regulation is a key to success in the energy business. For over 40 years, Regulatory Research Associates has been the leading provider of independent research, expert analysis, proprietary data and consultation on utility securities and regulation. S&P Global Commodity Insights produces content for distribution on S&P Capital IQ Pro.

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Financial News Investors Are Seeing – Continued

William Bernstein on Investors' Biggest Risk: Not Preparing for the Worst

by Glenn Ruffenach – WSJ – Aug. 11, 2023

The key, says the famed investment adviser, is to **hold enough safe, boring assets to keep** you **from panicking when** the **value** of your **other assets plummets.**

Investors 'overestimate their risk tolerance,' says William Bernstein

Quick question: When it comes to investing, would you describe yourself as Mr. Spock of "Star Trek" fame, or George Costanza from "Seinfeld"? In other words, are you an investor who's logical and dispassionate, or one who's impulsive and excitable?

Most of us, not surprisingly, like to think we're Mr. Spock. But when economic times are at their worst, many of us are more apt to resemble George.

So concludes William Bernstein, an investment adviser and author, in a new edition of his book, "The Four Pillars of Investing." First published in 2002, "Pillars" today is regarded as a classic among financial guides. In a recent conversation, Bernstein discussed why he has updated his book, how his thoughts about investing have evolved, and why investors need to rethink how they design and build a portfolio.

Here are edited excerpts from the conversation:

The lesson of Sylvia Bloom

WSJ: Why update “Pillars” now?

Bernstein: I’ve learned a thing or two in the past 20 years. For starters, I’ve become less enamored of a largely mathematical approach to personal finance. It does little good to master the math if you fail to understand financial history, the madness of crowds, and the enemy staring back at you in the mirror.

WSJ: You begin the new edition with a remarkable story about a legal secretary. Tell us about Sylvia Bloom.

Bernstein: Sylvia Bloom worked for 67 years as a secretary at a law firm in New York. She retired in 2014. When she died a few years later, her executor discovered that her estate was worth more than $9 million, consisting mainly of common stocks. No one, not even her husband, knew about it.

The 10 worst single-day percent declines* for U.S. stocks, 1981-2023:

Date	Cause	One-day fall
Oct. 19, 1987	Black Monday	-20.47%
March 16, 2020	Covid pandemic	-11.98
March 12, 2020	Covid pandemic	-9.51
Oct. 15, 2008	Global financial crisis	-9.03
Dec. 1, 2008	Global financial crisis	-8.93
Sept. 29, 2008	Global financial crisis	-8.79
Oct. 26, 1987	Black Monday aftershock	-8.28
Oct. 9, 2008	Global financial crisis	-7.62
March 9, 2020	Covid pandemic	-7.60
Oct. 27, 1997	Asian financial crisis	-6.87

*S&P 500 Index
Source: Hartford Funds

WSJ: How did she do it?

Bernstein: Some of it was common sense. She understood, and took advantage of, the magic of compound interest. She wasn’t trying to get rich quick, but rather to **get rich slow** – a much safer bet. Above all, she understood the concept of risk: how much would be required to meet her goals, and how much she could tolerate as she grew older.

I've come to realize that the most dangerous facet of investor overconfidence doesn't involve the ability to pick securities or money managers, but rather the ability to bear risk. In finance speak, our "relative risk aversion" is anything but constant, as theory assumes, but rather rises dramatically in the worst of times.

Sylvia Bloom weathered financial storms that would have shaken the confidence of 99% of investors. She did it by holding enough safe assets, in addition to common stocks, to see her through the worst of times. We like to think that we would do the same. But when your savings are melting before your eyes, you tend to panic.

WSJ: So what does Sylvia teach us?

Bernstein: The lesson I take from her story, and from my own experience as well, is that it's a huge, and usually fatal, mistake to design a portfolio without focusing primarily on those approximately 2% of times that will cause you to lose your nerve and violate **Charlie Munger**'s prime directive of compounding. As Munger, who is Warren Buffett's partner, puts it: "The **first rule of compounding** is to **never interrupt it unnecessarily**."

That means holding plenty of safe assets – like dull, low-yielding Treasury securities –and being prepared to see your risky assets get periodically, and hopefully temporarily, slaughtered. As I note in the book, there's a reason why **Buffett holds 20%** of Berkshire Hathaway in **Treasury bills and cash**.

The pillars

WSJ: Clearly, the one constant in the new edition is the "pillars" themselves. W hat are they, and why are they important?

Bernstein: Just as medical students have to master human anatomy, physiology, pathology and pharmacology before they lay hands on a patient, the competent investor must master **four basic subjects** before they handle real money.

They are: **investment theory**, which is the connection between risk and return, and how portfolios behave; **investment history**, which is what long-term returns look like and how markets occasionally go bonkers on both the upside and downside; **investment psychology**, which is how to master the irrationality of both yourself and other participants; and the **investment business**, which is how to protect yourself from brokers, advisers and investment companies.

Beware the Burn

WSJ: In the book, you discuss likely returns for stocks and bonds in the coming decades and the effect of those returns on **retiree**s' "**burn rate**" – how much of their nest egg gets spent each year. The numbers are sobering.

Bernstein: **From** the **mid-1920s to** the **mid-1990s, investors were blessed with real stock returns of 7%** and **real bond returns of 2%**. The reason for those high stock returns, in particular, was the dramatic increase in stock valuations over that period.

I think **a more reasonable real return over the next several decades will be about 4.5% for stocks** and about **1% for bonds**. When we plug those figures into a 30-year retirement, we confirm the suspicion of many retirement analysts that "3% is the new 4%." In other words, **if you want your nest egg to last 30 years**, you're much **safer pulling 3% or less from** your **savings each year than** the **popular 4%**.

In fact, I think if your burn rate is much above 3.5%, you're in the red zone.

WSJ: To sum up, what do you think are the **biggest mistakes** that **investors make**?

Bernstein: There are three big ones.

First, as already mentioned, they **overestimate** their **risk tolerance**.

Second, they fail to understand that whenever they buy or sell a stock, the **person on** the **other side of** that **trade** is likely someone named Warren Buffett or Goldman Sachs, or worse, a corporate executive who knows more about the company than even those two names do. It's like playing tennis against an invisible opponent, not realizing that the person on the other side of the net is Serena Williams.

Third, they imagine that the objective is to obtain the highest possible returns, to get rich. It's not; your **objective** is to minimize your chances of dying poor. Those are two entirely different things.

–

Yield Curve Draws More Scrutiny

by Sam Goldfarb and Peter Santilli – WSJ – Aug. 14, 2023

Wall Street is growing confident the U.S. can avoid a recession. But one key market indicator is still sending seemingly bleak signals.

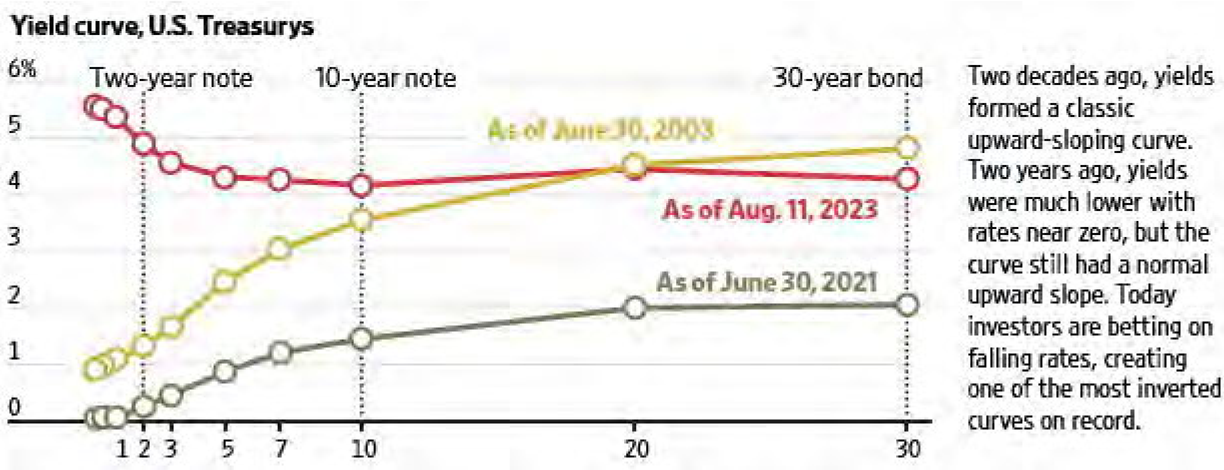
Right now, **yields** on **longer-term U.S. Treasurys** remain **far below** those of **shorter-term bonds**, an anomaly known as an **inverted yield curve** that has earned fame as a harbinger of downturns.

That has left many investors questioning what the inversion means now. Here is a look at the possible answers:

The Basics

A **yield curve shows** the **annualized percentage return**, or **yield**, that **investors can get on Treasurys**, from the three-month bill to the 30-year bond, **if held to maturity**.

Yields largely reflect investors' expectations for what short-term interest rates set by the Federal Reserve will average over the life of a bond – often plus a little extra for the risk of holding bonds for longer.



A Warning Signal

Inverted yield curves have taken on almost mythical status on Wall Street because of their recession-predicting record. One popular measure is the gap between yields on 10-year and two-year notes, known as the **2-10 spread**.

Is this time different?

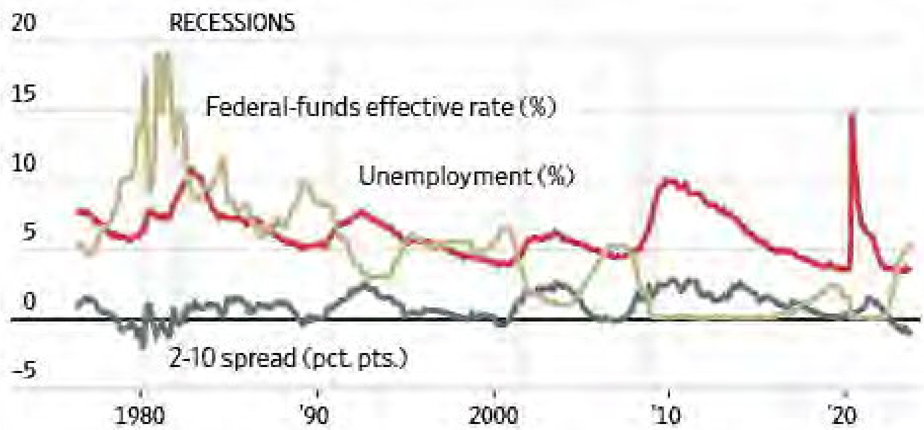
The simplest message sent by inverted yield curves is that investors think that short-term interest rates will be lower in the future than they are now. But that doesn't mean that a recession is guaranteed.

There have, in fact, been times when the Fed first raised, then lowered, rates and managed to skirt a recession. That might have even happened after it cut rates in 2019, if not for the pandemic.

Investors and economists have become more optimistic in recent months because inflation has subsided even as unemployment has remained near a five-decade low. That is true even of the Fed's preferred inflation gauge, which strips out volatile food and energy categories: As the Fed sees it, short-term rates, adjusted for short-term inflation expectations, are currently above a **neutral level** and therefore working to push inflation down.

Notably, bond yields and Fed forecasts both suggest that real rates will fall gradually over years before leveling off, a sign that investors and officials don't see a sharp economic downturn. Fed officials have also said that they might cut rates partly just to offset falling inflation, which would drive up real rates if they didn't take any action.

Spread between two-year and 10-year Treasury yields, with the federal-funds effective rate and unemployment rate, monthly*



Whenever the 2-10 spread has turned negative for at least two months, a recession has followed within the next year-and-a-half. Only the unusual pandemic recession wasn't preceded by an inversion of that length. Yield curves invert when the Fed is raising rates to cool the economy.

What to Watch for

The **economy doesn't typically enter** a **recession when** the **yield curve is inverted**. **Rather**, the **curve un-inverts shortly before** a **recession**, **with short-term bond yields falling because** the **Fed** is **cutting rates or** is **on** the **verge of doing so**.

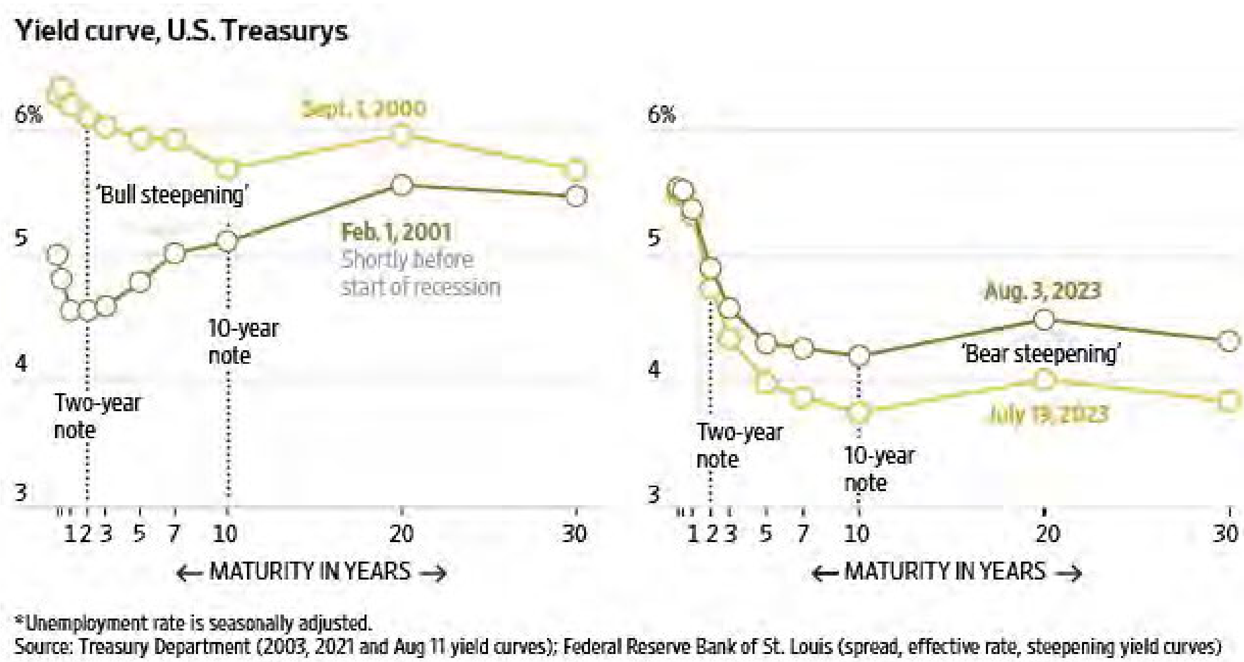
Analysts call this a "**bull steepening**" because bond prices are rallying, causing yields to fall, while the curve is getting steeper or un-inverting.

Recently, though, the bond market experienced a "**bear steepening**," in which longer-term yields rose sharply but short-term yields edged only slightly higher.

The curve was becoming less inverted but not in the normal way: Investors were growing more optimistic about the economy and scaling back bets on interest-rate cuts.

Going forward, analysts see a decent chance that the yield curve could stay inverted longer than normal, given the unusually large yield-gap and the strength of the economy.

But the **inversion will end eventually** and how it ends will be telling – whether the main cause is falling interest rates or new bets that the economy can withstand higher rates than previously believed.



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Bond Yield Hits Highest Since 2008, Adding Pressure to Borrowing Costs

by Sam Goldfarb – WSJ – Aug. 16, 2023

Bets that interest rates will fall have suppressed 10-year yields for most of 2023, but analysts warn that may be changing.

The **yield** on the **10-year U.S. Treasury note hit** a **15-year high**, threatening steeper costs for many borrowers and raising concern on Wall Street about the potential fallout in the stock, bond and housing markets.

A key benchmark for interest rates across the economy, the 10-year yield settled at **4.258%**, according to Tradeweb. That was up from 4.220% Tuesday and marked its **highest close since June 2008**, **months before** the **collapse** of **Lehman Brothers and expansive Federal Reserve policy ushered in more than** a **decade** of **historically low bond yields**.

The rise in yields is making investors nervous, because past surges have at times proved destabilizing for markets. With the 10-year yield still well below the level of short-term interest rates set by the Fed, some analysts see ample room for it to keep climbing – a development that could lead to unexpected disruptions, as investors are forced to unwind wagers based on projections for lower yields.

U.S. stocks fell Wednesday, with the Dow Jones Industrial Average dropping roughly 181 points, or 0.5%.

When investors start demanding higher yields on longer-term bonds to compensate for the risk of inflation, that "is correlated with lower risk-asset prices," said Zhiwei Ren, a portfolio manager at Penn Mutual Asset Management. "I think that's what markets are worried about right now."

The 10-year yield has been climbing for weeks based largely on a run of solid economic data, which has prompted many investors to abandon bets that the U.S. is headed toward a recession over the next six to 12 months. **Higher yields mean lower bond prices**.

Longer-term yields got an extra boost this month when the Treasury Department announced that it would need to borrow more than anticipated in the coming months to finance the federal budget deficit. That is forcing investors to buy more bonds than they might have wanted.

Long-term bond yields largely reflect investors' expectations for what short-term rates set by the Fed will average over the life of a bond, though they can also be affected by other factors, such as investor sentiment about the health of markets and the global economy.

The new milestone for the 10-year yield is a stark reminder of how much the economy has changed since the start of the Covid-19 pandemic.

The Federal Reserve last month raised interest rates to a 22-year high.

For years, **developed economies across** the **globe** appeared stuck in a perpetual state of **sluggish growth**, **tepid inflation** and **ultralow interest rates**, which even experiments with deficit-financed tax cuts or spending programs did little to change. **Now**, **central banks** are **working** hard **to tame inflation**, **short-term rates** are at their **highest levels in decades** and the **U.S. economy**, in particular, is **barely slowing down**. U.S. stock indexes have risen significantly this year.

"We're in a different world," said Leah Traub, a fixed-income portfolio manager at Lord Abbett.

The main difference, she said, is that inflation remains comfortably above the Fed's 2% target, which will make the central bank reluctant to cut interest rates even if the economy does start to falter.

In fact, **inflation** – which surged in 2021, driving the Fed to embark on a historic series of interest-rate increases in 2022 – has shown some **signs of cooling** in recent months.

That has made the recent jump in yields particularly noteworthy. Instead of betting that the Fed will have to raise interest rates ever higher to defeat inflation and then start cutting them once a recession arrives, investors are wagering that the Fed may be done raising rates but also further away from any cuts.

That has helped drive up longer-term bond yields relative to shorter-term ones, in a reversal of the dominant trend over the past year-and-a-half. Minutes of the Fed's most recent policy meeting released Wednesday afternoon added to recent signs that officials are growing more cautious about raising rates.

Higher yields have wide-ranging consequences for financial markets and the **economy**.

–

Rates Spur Cash Comeback

by Hannah Miao and Charley Grant

For the first time in years, investors earn robust returns on money accounts.

After more than a **decade** of **ultralow interest rates**, **Americans** finally **have choices in** their **hunt for yield**.

Before, they **earned next to nothing on money parked** in **checking or savings accounts**. Now, they are rushing to scoop up money-market funds and other cash-like instruments that are offering robust returns.

The **Federal** Reserve's aggressive **rate-raising** campaign to tame inflation **upended** the long-held **paradigm** that "**there is no alternative**" **to stocks**. After last year's stock-market selloff burned investors, many say they don't need to buy stocks when they can lock in a 5% return with little risk.

Keith Hagg, 50 years old, said equities made up nearly all of his investment portfolio before the pandemic, but lately he has been "stockpiling cash" in money-market funds and adding allocation to bonds as yields climbed.

"All of my investment experience was in a low-rate environment. I didn't see much value in having cash just sitting around in low-yielding accounts," said Hagg, a lawyer in Washington, D.C. "Now it's great to get that return."

Although stocks mounted an expectation-defying rebound this year, the rally stalled in recent weeks with the S& P 500 down 4.8% in August. Market participants are bracing for the potential of more rate increases ahead as the economy continues to show signs of strength.

Rates Offer More Yield Options

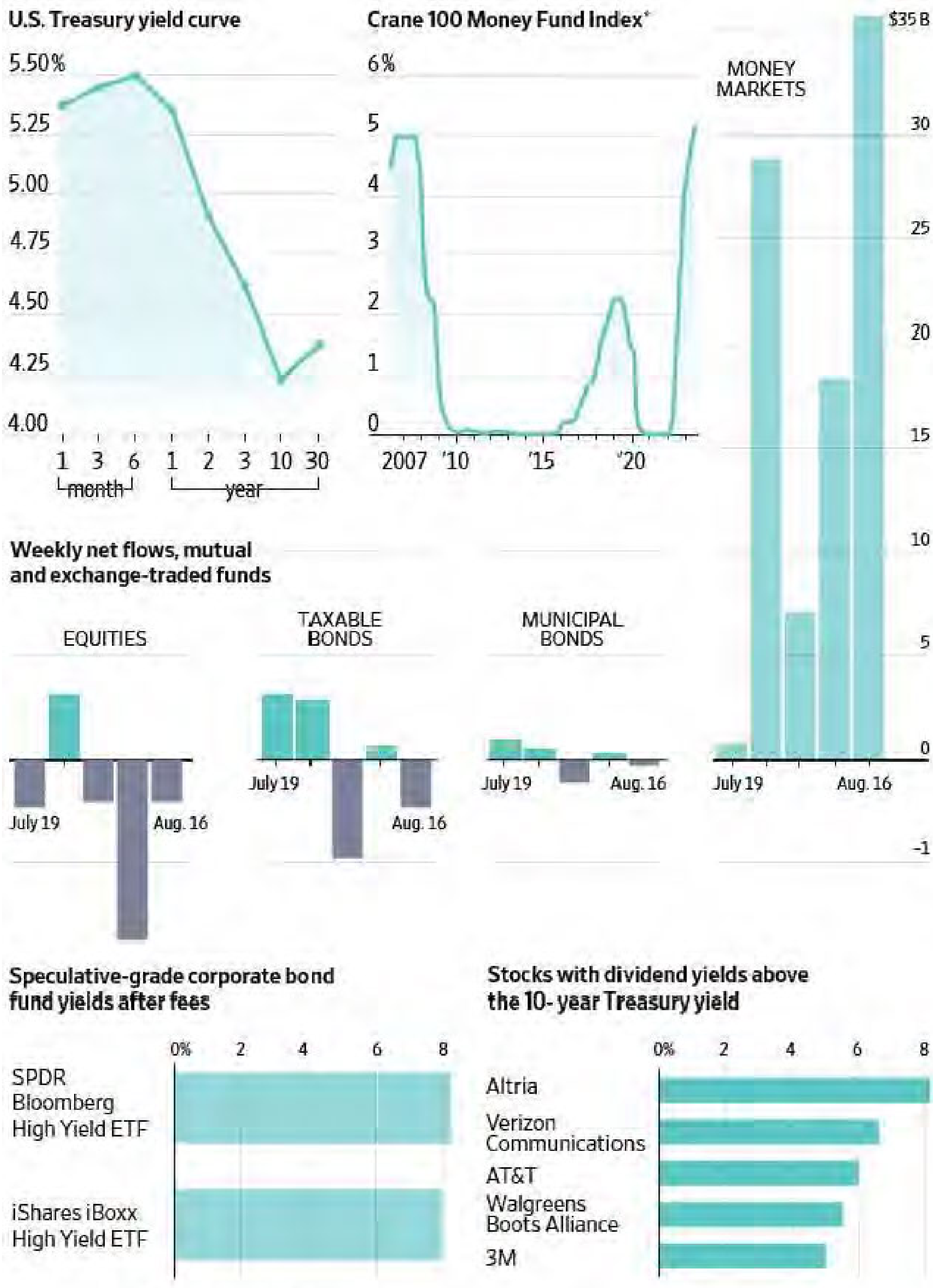
Investors yanked $11.6 billion from stock funds on a net basis over the past five weeks, while putting a net $91.1 billion into money-market funds, according to Refinitiv Lipper data as of Wednesday.

Here are some of the places investors have been putting their money to work:

Government bonds

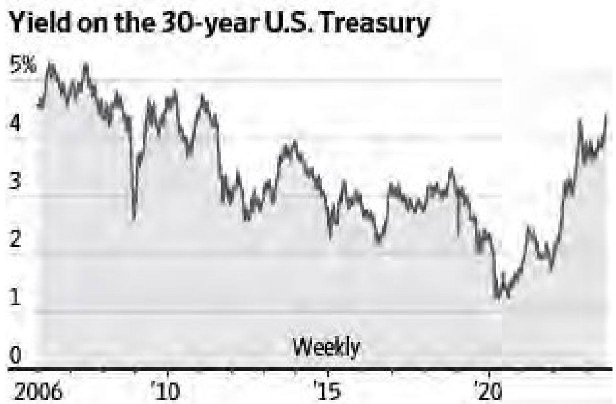
Payouts from Uncle Sam are generally **considered by investors** to be **free of default risk** and therefore among the safest assets around. **Yields** on most bonds are **fixed**, **however**, **so holders** of **Treasurys still bear risks like rising interest rates or** a **resurgence of inflation**.

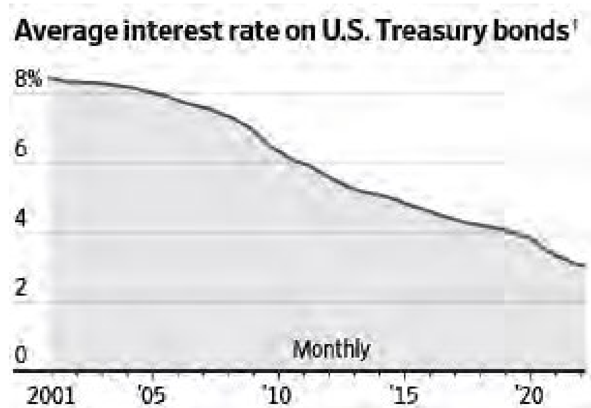
The **yield curve** is **still inverted**, meaning **short-term bonds yield more than longer ones**: The **one-month Treasury bill yields 5.37%**, while the **30year bond offers 4.38%**. The advantage of the longer-dated securities is the yields are locked in for longer – in case rates start falling again.

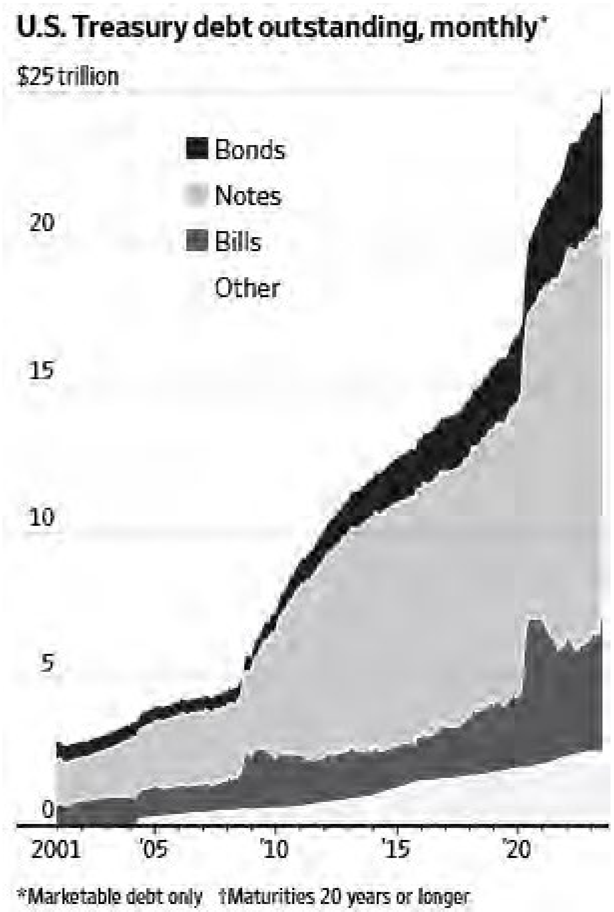


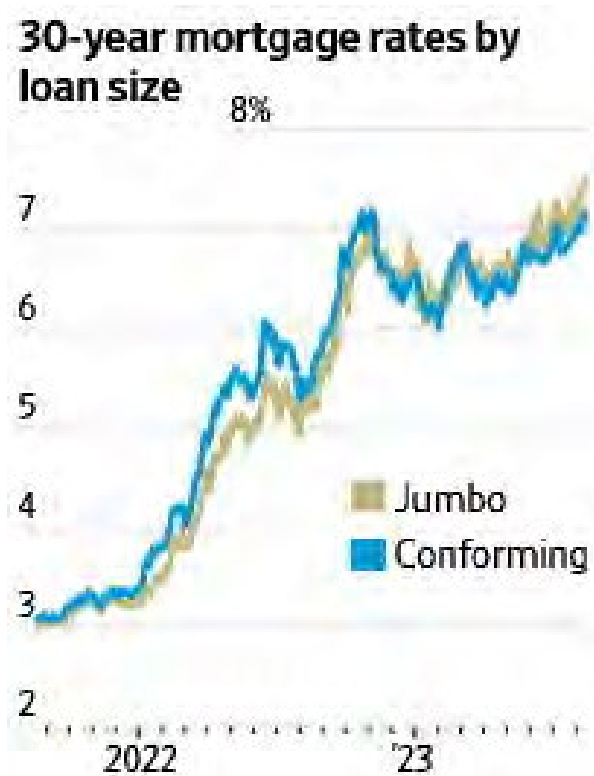
*Based on an average of the 100 largest taxable money funds

Sources: Tullett Prebon (treasury yield); Crane Data (money fund); Refinitiv Lipper (net flows); the funds (fund yields); FactSet (dividend yields)









Money-market funds

Cash in retail money-market funds has grown more than 25% this year to $1.5 trillion, according to Federal Reserve data. The average yield on the 100 largest taxable money-market funds reached 5.15%, according to Crane Data. That is the highest since 1999.

Money-market funds, which are a type of mutual fund that functions as a sort of bank account, are as safe as the bank that offers them. They hold only high-quality, liquid assets such as Treasurys and, in some cases, short-term corporate debt. Sometimes money-market funds require minimum balances and limit monthly withdrawals. Several funds offer yields comparable to those available from Treasurys, according to Bankrate.

Kevin Barker, a 38-year-old lawyer, said he sold most of his stockholdings earlier this year and put it into a Schwab money-market mutual fund, which is yielding more than 5%. He has been moving some cash from a savings account into the money-market fund, since it pays a higher rate. “I wasn’t comfortable with the amount of equity exposure I had in a turbulent market,” said Barker, who lives in Washington, D.C.

High-yield bond funds

Speculative-grade, or junk-rated, companies tend to offer higher rates to compensate investors for taking on greater risk. High-yield corporate bond funds can offer investors sizable income after fees, while offering diversification to protect against credit risk.

However, investors have been pulling money from high-yield corporate bond funds. Roughly $11 billion left those funds on a net basis this year, according to Refinitiv Lipper.

High-yielding stocks

For many years, more than **half** of **S&P 500 shares offered** a **dividend yield above** a **10-year Treasury**. **After** the **recent surge** in **long-term bond yields**, that club has **dwindled to just 52 companies**, including some that recently paid a one-time special dividend, according to FactSet.

Still, several household names, like tobacco company Altria and telecom giants **Verizon** Communications and **AT&T**, offer comparatively high dividend payouts. Companies typically pay large dividends or buy back stock when they don’t see better opportunities to invest their money in growth projects, so high dividend payers tend to be older, slow-growing firms.

Payouts can rise or fall based on each company’s financial performance and investment priorities, so they are **riskier yield options than** a **government bond**.

Paul Bhadha, a retired chemical engineer in Hollywood, Fla., said he is shifting from tech stocks to stocks that offer high dividends. He is putting money into Vanguard funds tracking shares of dividend-growing companies. Although he likes money-market funds and municipal bond funds, he said he isn’t ready to give up on stocks. "I know over the long term, the stock market is going to do great," Bhadha said.

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Montana Court Ruling on State's Greenhouse Gas Laws Is Credit Negative for NorthWestern

by Ryan Wobbrock – VP & Senior Credit Officer, Cole Egan – Assoc. Analyst, Nikita Nanwani – Assoc. Analyst, Michael G. Haggarty – Assoc. Managing Director
Moody's Credit Outlook – Aug. 21, 2023

On **14 August**, a **Montana district court judge ruled** that **state laws prohibiting** its **agencies from considering climate effects when evaluating fossil fuel projects were unconstitutional**. The **judge ruled** that **both laws HB 971 and SB 557** were **unconstitutional** and **invalidated certain provisions** of the **Montana Environmental Protection Act** (**MEPA**). HB 971 prohibited state agencies from evaluating greenhouse gas emissions (GHGs) and related climate effects in MEPA reviews, including those permitting fossil-fueled electric generation plants, while SB 557 implemented stricter legal standards for challenging state permitting under MEPA.

The **ruling** is **credit negative for** regulated utility **NorthWestern** Corporation (Baa2 stable) because it **creates uncertainty** within the legislative and judicial underpinnings of **Montana's regulatory framework**, a **key component** of the **NorthWestern's credit quality**. The ruling also reflects more challenging demographic and societal trends within the state: the **plaintiffs were 16 children** who alleged that state actions violated their right to a clean and healthy environment, while both the legislative and judicial branches have alternately opposed and supported greenhouse gas evaluations over the past five months. **Defendants** in the case **included** the **State of Montana**, **Montana's governor**, the **Montana Department of Environmental Quality** (**MDEQ**) and the **Montana Public Service Commission** (**MPSC**), among others. **We expect** that the **state will appeal** the ruling **and** that **litigation will be protracted**.

Furthermore, the ruling could call into question the existing air permit for the **Yellowstone County Generation Station** (**YCGS**), the company's **175-megawatt natural gas fired electric generation plant currently under construction**. **Construction** on the YCGS project had already been **halted** in **April**, following a **separate Montana District Court order** that **vacated YCGS's air quality permit** and required the MDEQ to address deficiencies in its permitting analysis. However, in June 2023, the court stayed the order pending the outcome of NorthWestern's appeal with the Montana Supreme Court. The **appeal** is **ongoing**, but NorthWestern was able to resume YCGS construction and expects the plant to be operational by the end of the third quarter 2024.

At a minimum, the branches of Montana's government have had a vacillating effect on NorthWestern's $275 million budgeted investment in Yellowstone, bringing greater uncertainty to both current and future capital spending. The **worst-case scenario** for the company would be a vacated air permit and **stranded investment** in the plant. NorthWestern has spent over $200 million on YCGS as of 30 June 2023. The state congress and governor were advocates of HB 971 and SB 557, so we expect that incremental efforts to support investments such as YCGS will ensue.

NorthWestern's cash flow from operations before changes in working capital (CFO pre-WC) **to debt** was just over **12% through** the **12 months ended 30 June 2023**, **below** its **downgrade threshold** of **14%**. However, CFO pre-WC to debt could rebound to around 14% because of a pending rate increase in Montana this year, a possible rate increase in its second largest service territory in South Dakota next year and the potential for YCGS recovery in 2025. The most important factor is its **current rate case** in **Montana**, where it has reached a **settlement** that is **pending** a **final order from** the **MPSC**.

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CASE: UE 416
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2908

Edison Electric Institute (EEI)
2023 Annual Financial Review Report

August 22, 2023

Edison Electric INSTITUTE

2022 Financial Review

Annual Report of the U.S. Investor-Owned Electric Utility Industry

Edison Electric INSTITUTE

2022 FINANCIAL REVIEW

ANNUAL REPORT OF THE U.S. INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY

About EEI and the Financial Review

The Edison Electric Institute (EEI) is the association that represents all U.S. investor-owned electric companies. Our U.S. members provide electricity for 220 million Americans and operate in all 50 states and the District of Columbia. As a whole, the electric power industry supports more than 7 million jobs in communities across the U.S. and contributes 5 percent to the nation's GDP. The 2022 Financial Review is a comprehensive source for critical financial data covering 39 investor-owned electric companies whose stocks are publicly traded on major U.S. stock exchanges. The report also includes data on five additional companies that provide regulated electric service in the United States but are not listed on U.S. stock exchanges because they are owned by holding companies not primarily engaged in the business of providing retail electric distribution services in the United States. These 44 companies are referred to throughout the publication as the U.S. Investor-Owned Electric Utilities. Please refer to page 76 for a list of these companies.

Contents

Highlights of 2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

FINANCIAL ($ Millions)	2022	2021r	% Change
Total Operating Revenues	$424,428	$366,615	15.8%
Utility Plant (Net)	$1,418,389	$1,335,697	6.2%
Total Capitalization	$1,368,875	$1,293,058	5.9%
Earnings Excluding Non-Recurring and Extraordinary Items	$51,221	$51,335	(0.2%)
Dividends Paid, Common Stock	$31,016	$30,075	3.1%

r = revised Note: Percent changes may reflect rounding.

Abbreviations and Acronyms

AFUDC	Allowance for Funds Used During Construction
BTU	British Thermal Unit
CFTC	Commodity Futures Trading Commission
CPI	Consumer Price Index
DOE	Department of Energy
DOJ	Department of Justice
DPS	Dividends per share
EEI	Edison Electric Institute
EIA	Energy Information Administration
EITF	Emerging Issues Task Force
EPA	Environmental Protection Agency
EPS	Earnings per share
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GW	Gigawatt
GWh	Gigawatt-hour
IPP	Independent Power Producer
IRS	Internal Revenue Service
ISO	Independent System Operator
ITC	Independent Transmission Company
kWh	Kilowatt-hour
M&A	Mergers & Acquisitions
MW	Megawatt
MWh	Megawatt-hour
NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxide
NOAA	National Oceanic & Atmospheric Administration
NRC	Nuclear Regulatory Commission
O&M	Operations and Maintenance
PSC	Public Service Commission
PUC	Public Utility Commission
PUHCA	Public Utility Holding Company Act
PURPA	Public Utility Regulatory Policies Act
ROE	Return on Equity
RTO	Regional Transmission Organization
SEC	Securities and Exchange Commission
SO_2	Sulfur Dioxide
T&D	Transmission & Distribution

Company Categories

Two categories are used throughout this publication that group companies based on their percentage of total assets that are regulated. These categories are used to provide an informative framework for tracking financial trends:

Regulated: 80% or more of total assets are regulated.

Mostly Regulated: Less than 80% of total assets are regulated.

Note: In prior editions of the Financial Review, a "Diversified" category was included for companies with less than 50% of total assets that are regulated. Some tables with historical data therefore include a "Diversified" category.

President's Letter

2022 Financial Review

In January 1933, EEI began representing America's investor-owned electric companies, just as electricity truly was beginning to revolutionize daily life and to propel our nation's economy. Ninety years later, we stand at a global energy inflection point—and demand for electricity continues to grow. In fact, U.S. electricity output hit a record annual high last year: an astonishing 4,142,901 gigawatt-hours, up 2.8 percent from 2021, and 0.7 percent above the previous record year of 2018.

Today, EEI's member companies remain focused on ensuring that customers have the energy they need when and where they need it, affordably and reliably, as we work to get this energy as clean as we can as fast as we can. And, we have fully embraced a strategy that will deliver secure and resilient clean energy across our economy.

In 2021, Congress delivered a once-in-a-generation investment in America's infrastructure with passage of the Bipartisan Infrastructure Law. Last year, lawmakers reaffirmed this commitment to addressing climate change with passage of the Inflation Reduction Act and its nearly $272 billion in clean energy tax credits. EEI strongly supported both laws, and we continue to lead implementation efforts to ensure that electric companies and state governments are taking advantage of these crucial investments in America's infrastructure.

While we continue to highlight the significance of these monumental new laws for our customers and for our member companies, we recognize that we face headwinds as well. Our suppliers and our customers continue to experience inflation levels that we have not seen for decades. At the same time, geopolitical tensions remain high with Russia's ongoing war in Ukraine. This continues to create fuel supply risks, while also impacting supply chains and significantly increasing cyber and physical security threats.

Despite these challenges and others, we are focused on the opportunities before us—and we are certain that our industry's future is bright. Today—just as we were 90 years ago—we are committed to demonstrating Power by Association℠ and to seizing the moment to deliver enduring benefits for our customers.

Thanks largely to the clean energy leadership of EEI's member companies, carbon emissions from the U.S. electric power sector today are as low as they were almost 40 years ago, while electricity use has climbed 73 percent since then. Already, 50 EEI member companies have announced ambitious emissions reduction commitments, 41 of which aim for net-zero or equivalent by 2050 or sooner. We are proud that more than 40 percent of our nation's electricity now comes from clean, carbon-free sources, including nuclear energy, hydropower, wind, and solar energy.

EEI's long-held position is that we need to take an economy-wide approach to reducing carbon emissions. This means transitioning more of the U.S. economy to clean, efficient electric energy—starting with the industrial and transportation sectors, especially as the latter has been the leading source of carbon emissions in the United States since 2016.

There are more than 3 million EVs already on U.S. roads, and EEI projects there will be at least 26 million on our roadways in 2030. That increase will require approximately 140,000 EV fast charging ports across the country—a 10-fold increase over today. EEI's member companies are investing more than $4 billion in programs to accelerate electric transportation, including the deployment of EV charging infrastructure.

For electric companies, the EEI-AGA ESG Sustainability Template lends itself to telling the story of our member companies' clean energy transition, the risks and opportunities that lie ahead, and their plans to manage them. Almost 7 years ago, EEI established the first-of-its-kind, sector-wide ESG reporting template working with our member companies, investors, and other key stakeholders. Today, our industry's ESG leadership has enabled EEI to work with the U.S. Securities and Exchange Commission as it establishes workable ESG climate reporting and cyber reporting and governance rules.

We also are working every day to improve energy grid security, reliability, and resiliency, and we continue to strengthen cyber and physical defenses and to enhance preparedness. Our strong industry-government partnership, coordinated through the CEO-led Electricity Subsector Coordinating Council, continues to be critical to accomplishing our shared goal of protecting the grid against all threats.

Recent events, including extreme weather events, reinforce the continued need for strategic and responsible investments in adaptation, hardening, and resilience (AHR). Over the past decade, EEI's member companies have invested more than $1 trillion in critical energy infrastructure. And, in 2022 alone, nearly $30 billion was invested in AHR initiatives to strengthen the nation's transmission and distribution infrastructure.

While investments in AHR have increased significantly over the past decade, more investments are needed to meet the challenges of climate change and to enhance the overall reliability and resilience of the grid. The benefits of smart investments in AHR are clear and allow electric companies, communities, and customers to be better equipped to operate through challenging conditions. In Florida, for example, the state's hardened energy infrastructure largely withstood a direct hit by Hurricane Ian last year. Moreover, the investments made in smarter energy infrastructure at the distribution level helped to avoid hundreds of thousands of customer outages—and significantly sped restoration times for customers who were impacted.

It is critical that electric companies can continue to make needed investments today that will help them to deliver a resilient clean energy future. EEI continues our advocacy for stable, constructive policies that support our member companies' infrastructure investments. Related to this, we are asking the U.S. Treasury Department to implement the Corporate Alternative Minimum Tax without unduly impacting electricity customers or undermining needed investment in grid infrastructure.

As you will see in this year's Financial Review, EEI's member companies continue to build upon a strong financial foundation. The industry's average credit rating was BBB+ for the ninth straight year in 2022, after increasing from the BBB average that previously had held since 2004. This improved credit quality greatly supports the continued level of elevated capital expenditures, which set an eleventh consecutive record high of $147.7 billion in 2022. We continue to be America's most capital-intensive industry.

The EEI Index returned 1.2 percent for 2022, outperforming the major averages. The S&P 500 Index returned -18.3 percent, the Dow Jones Industrial Average returned -7.0 percent, and the Nasdaq Composite saw a steep -33.5 percent decline. The EEI Index has produced a positive total return in 17 of the last 20 years, with returns of greater than 10 percent in 13 of the 17 positive years.

Our industry also extended its long-term trend of widespread and consistent dividend increases last year, with a total of 34 companies increasing their dividend in 2022. The percentage of companies that raised or reinstated their dividend in 2022 was 87 percent, up from 82 percent in 2021 and aligned with the 85 percent to 93 percent range seen from 2015 through 2020. Our industry's dividend payout ratio was 73.0 percent for the 12 months ended December 31, 2022, leading among the other major U.S. business sectors. As of December 31, 2022, 38 of the 39 companies in the EEI Index were paying a common stock dividend.

As we celebrate 90 years of Power by Association—and as we begin our next 90 years by engaging on our ambitious agenda—EEI and our member companies will be the catalyst for delivering resilient clean energy and for achieving a clean energy economy quickly and affordably.

Earlier this year, I announced my plans to step down as EEI President after more than 30 years. Few people have been as fortunate as I have to be associated with such a talented and dedicated team and to be part of such a vital industry. I am incredibly proud of what EEI and our member companies have accomplished together during my tenure.

EEI's mission to deliver Power by Association will remain unchanged. I am excited by what the future holds for our customers, our country, and our member companies—and I am excited to remain actively involved in our industry.

Over the years I have been involved in our industry, I have seen incredible transformation and progress—and I know that this transformation and this progress will never stop. Our industry's focus on our customers remains our North Star, and, by keeping them at the forefront, we will achieve amazing things.

We truly value the partnership that we share with the financial community.

Thomas R. Kuhn

President
Edison Electric Institute

Capital Markets

Stock Performance

Major market indices rebounded later in the year after three straight quarters of losses. The Dow Jones Industrial Average, a composite of 30 underlying large-capitalization companies, gained 15.8% while the more broadly diversified S&P 500 Index gained 7.3%. The tech-heavy Nasdaq, the epicenter of late 2021's market froth, edged down a modest 1.6%. Utilities were right in the middle; the EEI Index gained 8.8% for the quarter.

The full-year 2022 picture shows utilities far ahead of major indices on a relative basis. The Dow Jones Industrial Average returned -7.0% in 2022, the S&P 500 returned -18.3% and the Nasdaq fell deep into a bear market with a 33.5% decline.

Economic Growth Rebounds After Weak First Half

Markets in the second half of the year were powered higher in part by evidence that economic strength rebounded from weakness in 2022's first half. In late October, the Bureau of Economic Analysis (BEA) released its first estimate of Q3 2022 real GDP at positive 2.6%; this compared to -1.6% in Q1 and -0.6% for

2022 Index Comparison

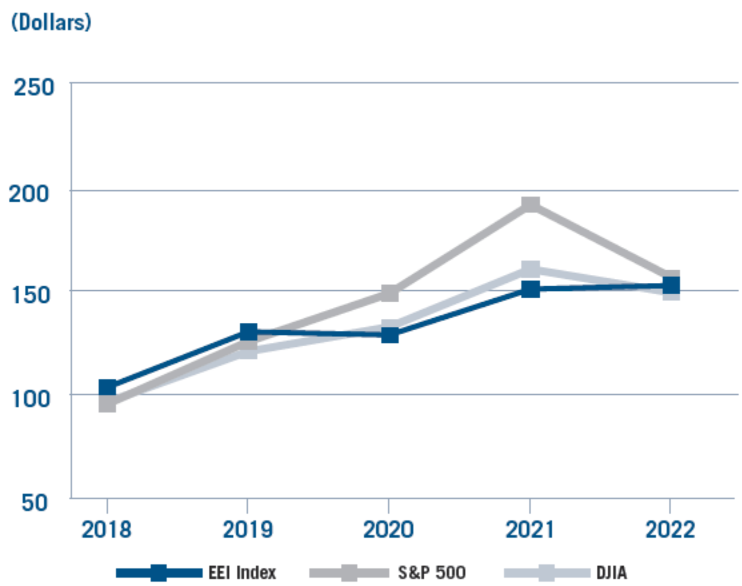
EEI Index	**1.2**
Dow Jones Industrials	(7.0)
S&P 500	(18.3)
Nasdaq Composite Index*	(33.5)

* Price gain/(loss) only. Other indices show total return.

Source: EEI Finance Department and S&P Global Market Intelligence.

Comparison of the EEI Index, S&P 500, and DJIA Total Return 1/1/18–12/31/22

REFLECTS REINVESTED DIVIDENDS



All returns are annual.
Note: Assumes $100 invested at closing prices December 31, 2017.

Source: EEI Finance Department and S&P Global Market Intelligence.

EEI Index Top 10 Performers
Twelve-month period ending 12/31/2022

Company	Total Return %	Category
PG&E Corporation	33.9	R
Sempra Energy	20.3	R
Consolidated Edison, Inc.	15.6	R
Unitil Corporation	15.1	R
Pinnacle West Capital Corporation	12.9	R
American Electric Power Company, Inc.	10.4	R
PNM Resources, Inc.	10.2	R
CenterPoint Energy, Inc.	10.1	R
Avista Corporation	8.8	R
NorthWestern Corporation	8.5	R

Note: Return figures include capital gains and dividends.
Source: EEI Finance Department.

Sector Comparison 2022 Total Shareholder Return

Sector	Total Return %
Oil & Gas	61.5%
Utilities	2.9%
EEI Index	**1.2%**
Healthcare	-4.7%
Telecommunications	-6.5%
Basic Materials	-6.9%
Financials	-13.3%
Industrials	-13.5%
Consumer Goods	-23.2%
Consumer Services	-30.6%
Technology	-34.9%

Source: EEI Finance Dept., Dow Jones & Company, Yahoo! Finance.

Q2. The Q3 figure was revised upward to 2.9% in the late November release and higher again to 3.2% in the BEA's third estimate, released on December 22.

Headline Inflation Moderates

Investor sentiment was also lifted by hints that inflation may be moderating. Inflation measured by the headline consumer price index (CPI) for urban consumers peaked in June at 8.9% and held above 8% in July, August, and September. Data released in Q4 showed a steady decline to 7.8% in October, 7.1% in November and 6.4% in December. The CPI excluding volatile food and energy (which economists often cite as a more meaningful inflation metric) hovered near 6% all year and peaked in September at 6.6%, yet it too eased to a December reading of 5.7%.

Fed Hikes but Bond Yields Ease

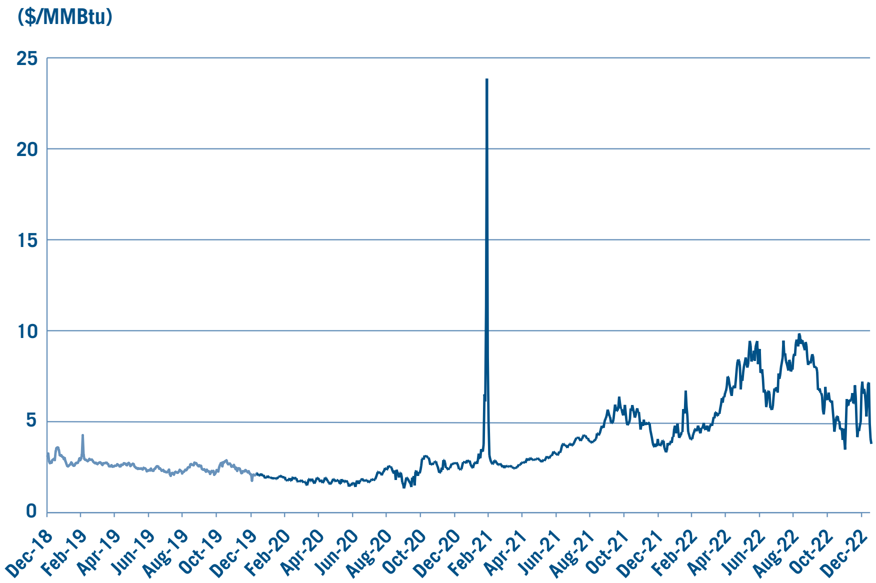
Persistently sticky inflation data was enough to cause the U.S. Federal Reserve to extend it's 2022 rate hike campaign, hiking the overnight federal funds rate by 75 basis points on November 2 and 50 basis points on December 14. The Fed's seven rate hikes in 2022 took the fed funds rate from near 0% in March to 4.3% in late December, making for one of the steepest rate-hike campaigns in modern history.

Bond markets spent Q4 wondering how to react to Fed hikes and cooler inflation data. The U.S. 10-year Treasury yield rose in October, reaching 4.2%, but then fell steadily to 3.4% by early December before climbing back to 3.8% at year-end, and corporate bond yields were steady for the quarter. Falling inflation numbers and steady bond yields gave investors enough confidence to push markets up after three quarters of losses.

Fuel Cost Inflation Drives up Power Prices

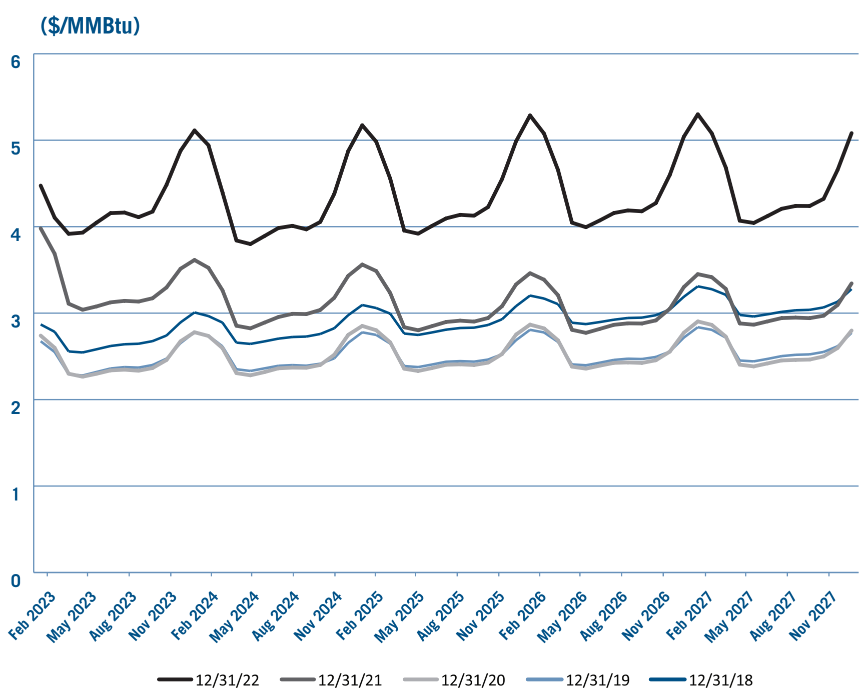
While surging inflation and higher energy costs are a global phenomenon, the trend is impacting U.S. electricity costs. Natural gas powers about 38% of generation nation-

Natural Gas Spot Prices - Henry Hub
12/31/18 through 12/31/22



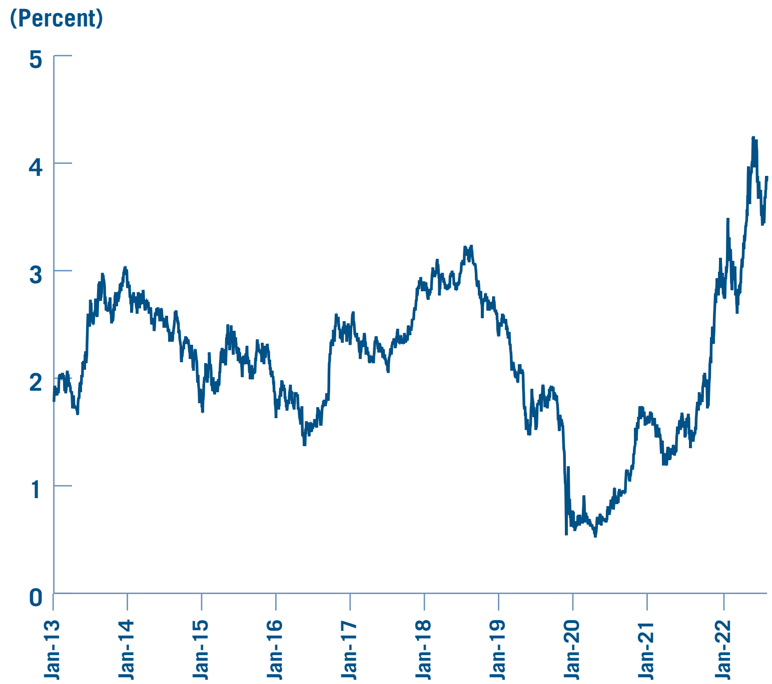
Source: S&P Global Market Intelligence.

NYMEX Natural Gas Futures
February 2023 through December 2027



Source: S&P Global Market Intelligence.

10-Year Treasury Yield
1/1/13 through 12/31/22



Source: U.S. Federal Reserve.

wide and coal about 22%. Natural gas prices have been rising since the middle of 2020 and jumped in 2022 to their highest levels since 2013. Regulated utilities pass fuel costs through to rates under state regulation and have little near-term control over the fuel element of the utility bill. EIA data shows the average cost of natural gas for electricity generation rose 110% year-to-year in Q2 and 86% in Q3. EIA data shows that comparable coal costs rose 11% year-to-year in Q1, 16% in Q2 and 22% in Q3.

Natural gas comparisons eased in tandem with CPI inflation in Q4, echoed by the decline in spot gas prices seen in the graph *Natural Gas Spot Prices*. The average cost of natural gas for electric generation rose only 5.0% in October and was unchanged year-to-year in November. However, inflation in the average cost of coal for electricity generation remained high, at 22.0% in October and 25.9% in November.

While electricity rates in aggregate nationwide were mostly flat from 2008 through 2019, the average retail price of electricity nationwide according to EIA data rose 7% year-to-year in 2022's Q1, more than 12% in Q2 and almost 17% in Q3. Cost pressures continued in Q4 with year-to-year increases at 14.0% in October and at 11.8% in November.

Utility managements and Wall Street analysts are closely watching rate reviews and regulators' reactions to integrated resource plans to see if cost pressures on utility bills spoil consumers' or regulators' support for the clean energy capex that drives earnings growth.

Conference Season

Wall Street analysts produce considerable reporting on utility management presentations at the investment conferences that populate the fall season. EEI's Financial Conference in November is one of these. In recent years, Wall Street's take has been consistently upbeat, focusing on the virtuous cycle that enabled low natural gas prices, stable customer bills, growing public support for clean energy and for CO2 emissions cuts, federal clean renewable energy tax incentives, and operations and maintenance (O&M) cost savings from smart-grid investments to fund the growing capital spending that translates into earnings growth. Projected secular earnings growth rates analysts cited for utilities steadily edged higher over the past decade from 4%-5% up to 5%-7% and 6%-8% in some cases.

This year's conference season produced widespread discussion of inflation, higher interest rates, higher fuel costs, pension costs pressures, regulatory concern over the impacts of aggressive capex on customer bills, and the stability of long-term earnings growth rates across the industry. Several analyst reports used the phrase "non-linearities" to reference the modest cuts in 2023 earnings guidance or longer-term growth outlooks that came out of earnings calls and conference presentations by a handful of utilities. The phrase was also a buzzword for investors' new scrutiny of company outlooks for risks of earnings speed bumps or downshifts to expected growth rates.

Secular Tailwinds

Yet despite scattered earnings outlook cuts, Wall Street research coverage also affirmed the industry's fundamental growth picture remains robust.

The Inflation Reduction Act of 2022 (IRA) offers broad support to the nation's clean energy agenda and may add to pre-existing rate base growth opportunities for electric utilities. In EEI's view, the IRA places the United States at the forefront of global efforts to drive down carbon emissions, especially when paired with the historic funding included in the bipartisan infrastructure law. It also provides much-needed certainty to electric utilities over the next decade, as they work to deploy clean energy and carbon-free technologies.

Analysts noted that, despite regulatory scrutiny of customer bill pressures in some regions, there is little evidence that commissions are generally any less supportive of the nation's clean energy agenda and the economic stimulus that clean energy and reliability-related capex brings to service territories. The potential boost to secular load growth from widespread adoption of electric vehicles also remains a possibly strong tailwind. Several utilities have cited the onshoring of U.S. manufacturing and economic development as drivers of strong load growth in their service territories. A few cited electricity demand from large data centers.

Long-term growth rarely occurs without occasional setbacks and challenges. And utilities offered investors a relative safe haven and a positive total return in 2022's market weakness — that's more or less what they're expected to do. It's impossible to predict what inflation and interest rates will do in 2023, but as the year begins it seems reasonable to believe the nation's clean energy revolution is still in the early innings with investor-owned utilities as key players in the game.

2022 Returns By Quarter

Index	Q1	Q2	Q3	Q4
EEI Index	4.8	(4.9)	(6.7)	8.8
Dow Jones Industrial Average	(4.0)	(10.9)	(6.2)	15.8
S&P 500	(4.6)	(16.1)	(4.9)	7.3
Nasdaq Composite*	(9.0)	(23.0)	(3.5)	(1.6)
Category	**Q1**	**Q2**	**Q3**	**Q4**
All Companies	5.2	(3.8)	(8.3)	10.7
Regulated	6.4	(3.6)	(8.2)	10.0
Mostly Regulated	(0.0)	(5.0)	(9.0)	14.3

* Price gain/loss only. Other indices show total return.
For the Category comparison, straight, equal-weight averages are used (i.e., not market-cap-weighted).

Source: EEI Finance Department, S&P Global Market Intelligence.

2022 Category Comparison

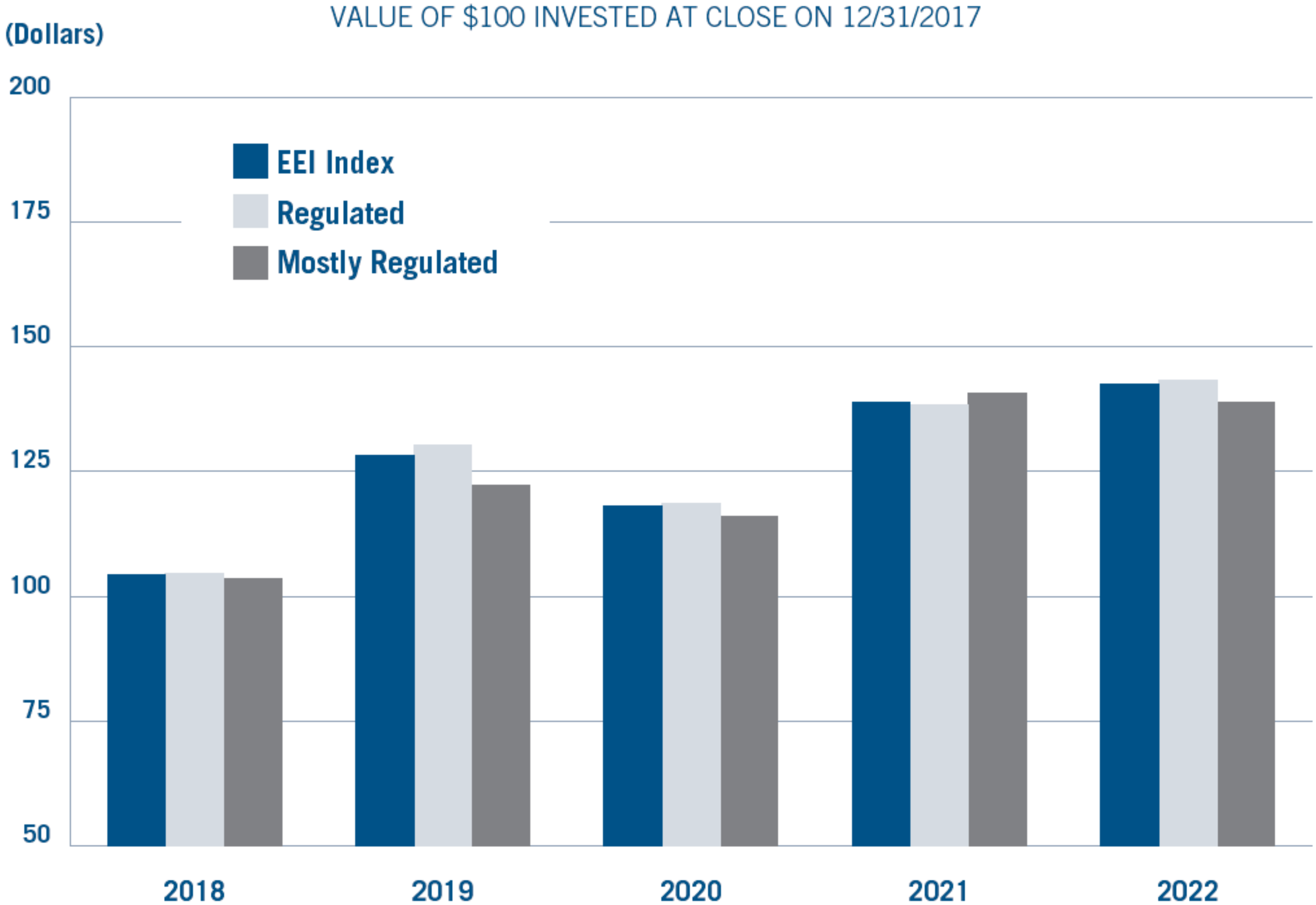
Category	Return (%)
EEI Index	**2.7**
Regulated	3.6
Mostly Regulated	(1.1)

* Returns shown here are unweighted averages of constituent company returns. The EEI Index return shown in the 2022 Index Comparison table is cap-weighted.

Source: EEI Finance Department, S&P Global Market Intelligence, and company annual reports.

Comparative Category Total Annual Returns 2018–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES,
VALUE OF $100 INVESTED AT CLOSE ON 12/31/2017



	2018	2019	2020	2021	2022
EEI Index Annual Return (%)	4.28	23.06	(8.07)	17.62	2.74
EEI Index Cumulative Return ($)	104.28	128.32	117.96	138.74	142.55
Regulated EEI Index Annual Return	4.55	24.56	(9.01)	16.72	3.59
Regulated EEI Index Cumulative Return	104.55	130.22	118.49	138.30	143.26
Mostly Regulated EEI Index Annual Return	3.62	17.87	(4.95)	21.09	(1.15)
Mostly Regulated EEI Index Cumulative Return	103.62	122.14	116.09	140.58	138.97

- For the Category Comparison, straight, equal-weight averages are used (i.e., not market-cap-weighted).
- Cumulative Return assumes $100 invested at closing prices on December 31, 2017.

Source: EEI Finance Dept., S&P Global Market Intelligence.

Market Capitalization at December 31, 2022 (in $MM)

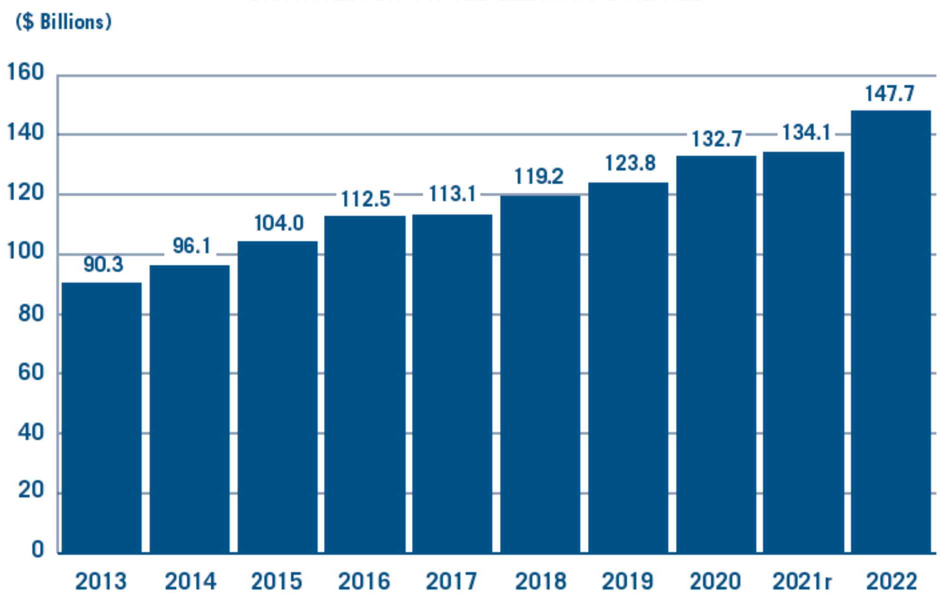
U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Ticker	Market Cap.	% of Total
NextEra Energy, Inc.	NEE	164,901	16.49%
Duke Energy Corporation	DUK	79,302	7.93%
Southern Company	SO	77,266	7.73%
Dominion Energy, Inc.	D	51,055	5.11%
American Electric Power Company, Inc.	AEP	48,779	4.88%
Sempra Energy	SRE	48,637	4.86%
Exelon Corporation	EXC	42,711	4.27%
Xcel Energy Inc.	XEL	38,420	3.84%
Consolidated Edison, Inc.	ED	33,797	3.38%
PG&E Corporation	PCG	32,309	3.23%
Public Service Enterprise Group Inc.	PEG	30,451	3.05%
WEC Energy Group, Inc.	WEC	29,572	2.96%
Eversource Energy	ES	29,117	2.91%
Edison International	EIX	24,303	2.43%
FirstEnergy Corp.	FE	23,948	2.40%
Ameren Corporation	AEE	22,977	2.30%
Entergy Corporation	ETR	22,888	2.29%
DTE Energy Company	DTE	22,683	2.27%
PPL Corporation	PPL	21,513	2.15%
CenterPoint Energy, Inc.	CNP	18,879	1.89%
CMS Energy Corporation	CMS	18,340	1.83%
AVANGRID, Inc.	AGR	16,622	1.66%
Evergy, Inc.	EVRG	14,468	1.45%
Alliant Energy Corporation	LNT	13,858	1.39%
NiSource Inc.	NI	11,146	1.11%
Pinnacle West Capital Corporation	PNW	8,609	0.86%
OGE Energy Corp.	OGE	7,918	0.79%
MDU Resources Group, Inc.	MDU	6,170	0.62%
IDACORP, Inc.	IDA	5,465	0.55%
Hawaiian Electric Industries, Inc.	HE	4,581	0.46%
Black Hills Corporation	BKH	4,563	0.46%
Portland General Electric Company	POR	4,374	0.44%
PNM Resources, Inc.	PNM	4,201	0.42%
ALLETE, Inc.	ALE	3,684	0.37%
NorthWestern Corporation	NWE	3,341	0.33%
Avista Corporation	AVA	3,247	0.32%
MGE Energy, Inc.	MGEE	2,546	0.25%
Otter Tail Corporation	OTTR	2,442	0.24%
Unitil Corporation	UTL	822	0.08%
Total Industry		**999,904**	**100%**

Source: EEI Finance Department and S&P Global Market Intelligence.

Capital Expenditures 2013–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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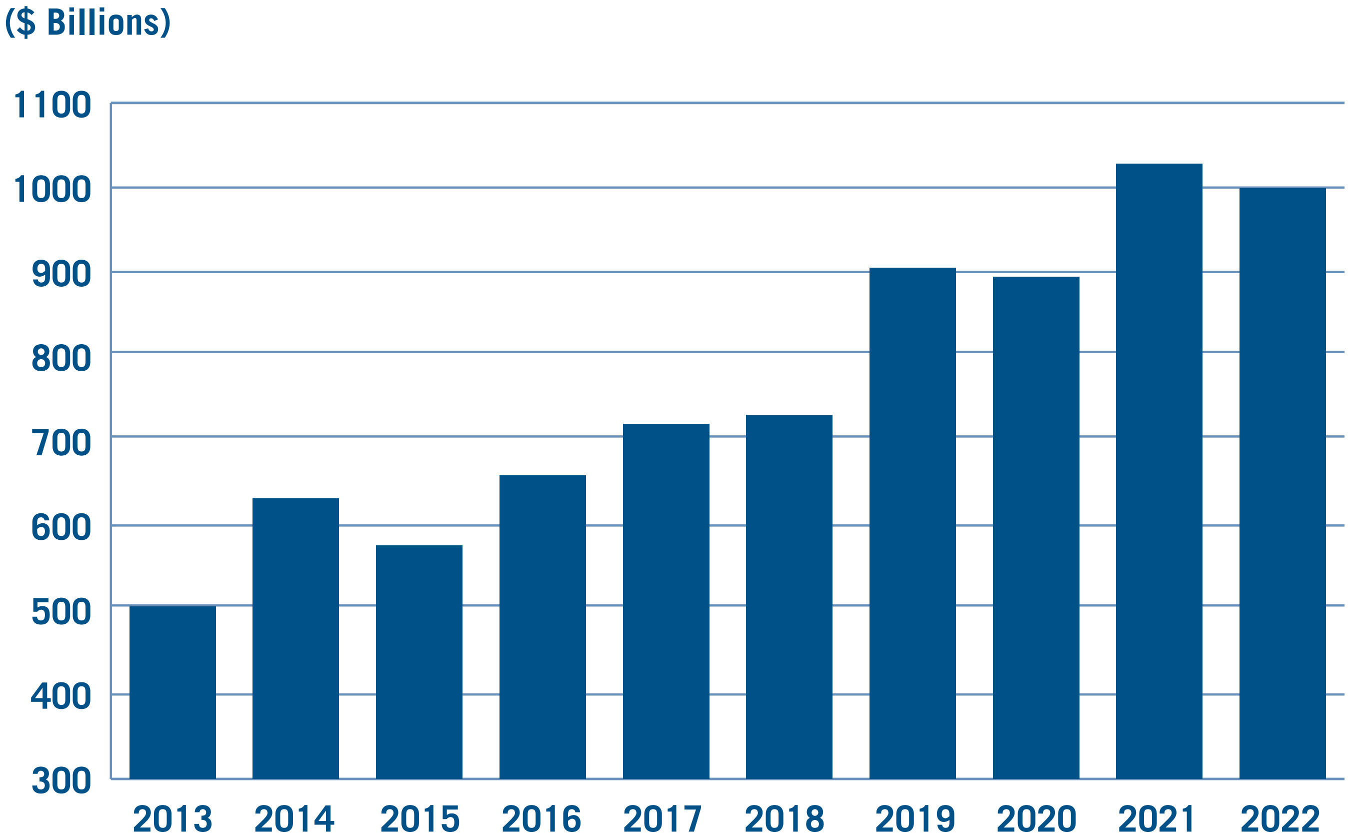
Source: S&P Global Market Intelligence, company reports, and EEI Finance Department.

EEI Index Market Capitalization 2013–2022

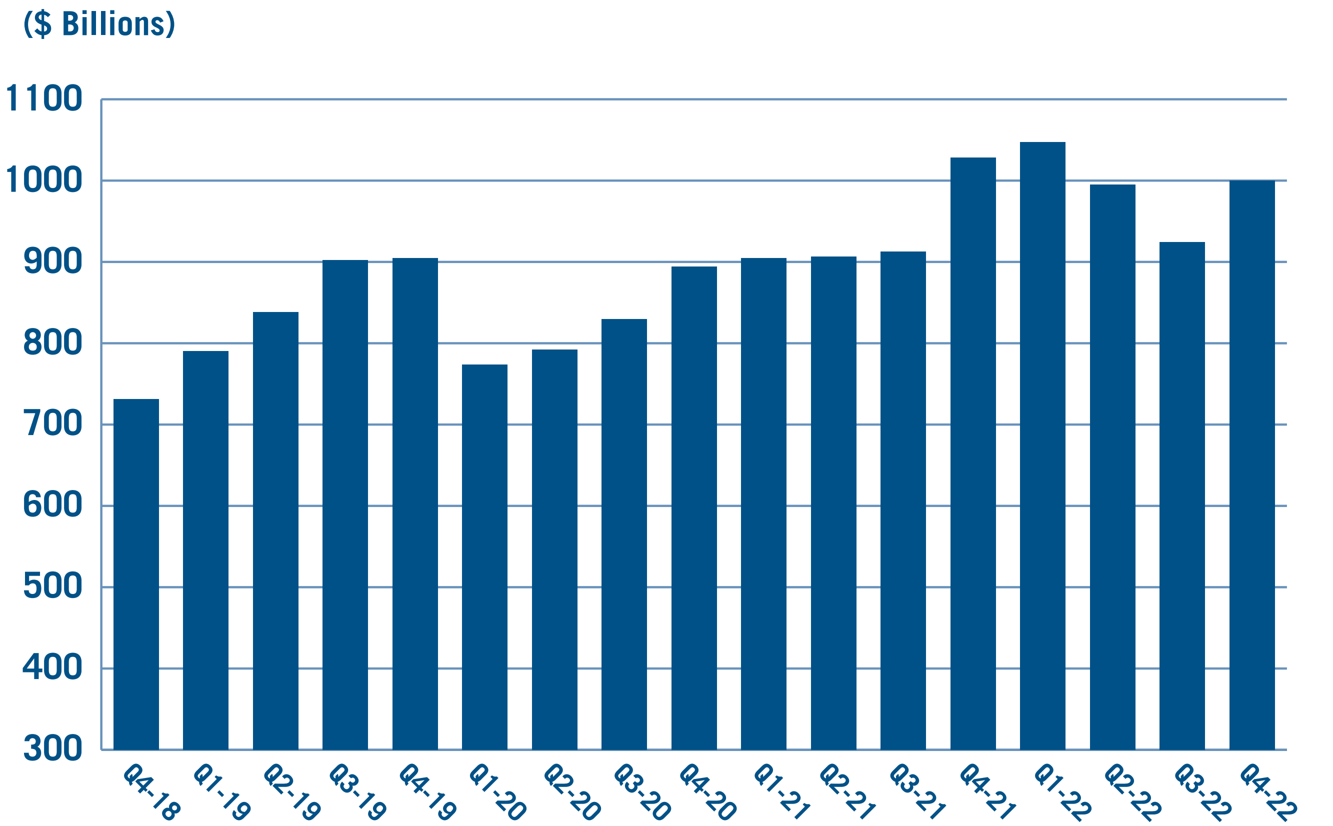


Note: Results are as of December 31 of each year.

Source: EEI Finance Department and S&P Global Market Intelligence.

EEI Index Market Capitalization

December 31, 2018–December 31, 2022



Source: EEI Finance Department and S&P Global Market Intelligence.

Dividends

The investor-owned electric utility industry continued its long-term trend of widespread dividend increases in 2022. A total of 34 companies increased or reinstated their dividend compared to 32 in 2021, 34 in 2020, 37 in 2019, 39 in 2018 and 36 to 40 companies annually from 2012 through 2017. There was one dividend reduction compared to zero in 2021 and two in 2020.

The percentage of companies that raised or reinstated their dividend in 2022 was 87%, up from 82% in 2021 and aligned with the 85% to 93% range seen from 2015 through 2020. By contrast, only 27 of the 65 utilities tracked by EEI increased their dividend in 2003, just prior to the passage of legislation that reduced dividend tax rates. The percentages noted above are drawn

Dividend Patterns 1996–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Raised	No Change	Lowered	Omitted*	Reinstated	Not Paying	Total	Dividend Payout Ratio
1996	48	44	2	1	1	2	98	70.7%
1997	40	45	6	2	–	3	96	84.2%
1998	40	37	7	–	–	5	89	82.1%
1999	29	45	4	–	3	2	83	74.9%
2000	26	39	3	1	–	2	71	63.9%
2001	21	40	3	2	–	3	69	64.1%**
2002	26	27	6	3	–	3	65	67.5%
2003	26	24	7	2	1	5	65	63.7%
2004	35	22	1	–	–	7	65	67.9%
2005	34	22	1	1	2	5	65	66.5%
2006	41	17	–	–	–	6	64	63.5%
2007	40	15	–	–	3	3	61	62.1%
2008	36	20	1	–	1	1	59	66.8%
2009	31	23	3	–	–	1	58	69.6%
2010	34	22	–	–	–	1	57	62.0%
2011	31	22	–	1	1	–	55	62.8%
2012	36	14	–	–	1	–	51	64.2%
2013	36	12	1	–	–	–	49	61.5%
2014	38	9	1	–	–	–	48	60.4%
2015	39	7	–	–	–	–	46	67.0%
2016	40	4	–	–	–	–	44	62.9%
2017	38	4	–	1	–	–	43	64.0%
2018	39	1	1	–	–	1	42	63.9%
2019	37	2	–	–	–	1	40	62.6%
2020	34	2	2	–	–	1	39	65.3%
2021	32	6	–	–	–	1	39	62.7%
2022	34	3	1	–	–	1	39	70.8%

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Average of the Increased Dividend Actions ***	5.3%	5.7%	5.8%	5.6%	5.6%	5.7%	5.1%	5.1%	4.8%	5.2%
Average of the Declining Dividend Actions ***	(41.0%)	(34.5%)	NA	NA	NA	(79.8%)	NA	(40.6%)	NA	(51.8%)

* Omitted in current year. This number is not included in the Not Paying column.

** * Prior to 2000: Total industry dividends/total industry earnings. Starting in 2000: Average of all companies paying dividend.

*** Excludes companies that omitted or reinstated dividends.

2022 current year figures reflect dividend changes (raised, lowered, etc.) through 12/31/2022 and earnings and dividends through 12/31/2022 (payout ratio).

Source: S&P Global Market Intelligence and EEI Finance Department from a dataset that begins in 1988. Mergers and acquisitions reduced the number of publicly traded utilities included in the EEI Index from 65 in 2003 to 39 at year-end 2022.

As shown in Dividend Patterns table, 38 of the 39 publicly traded utilities in the EEI Index were paying a common stock dividend as of December 31, 2022. Each company is limited to one action per year in the table. For example, if a company raised its dividend twice during a year that counts as one in the Raised column. Electric utilities generally use the same quarter each year for dividend changes, with Q1 being the most common.

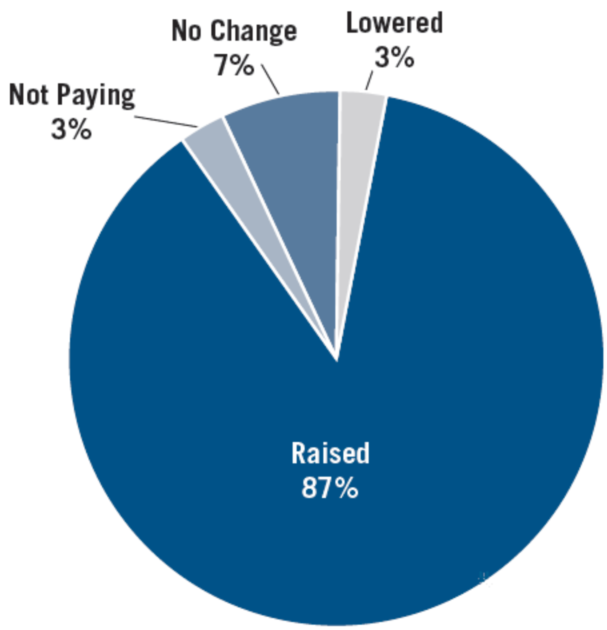
2022 Increases Average 5.2%

The average dividend increase in 2022 was 5.2%, with a range of 1.0% to 12.2% and a median increase of 5.6%. PNM Resources (12.2% including both its Q1 and Q4 raises), CenterPoint Energy (11.8% including both its Q3 and Q4 increases) and NextEra Energy (+10.4% in Q1) posted the largest percentage increases.

PNM Resources, headquartered in Albuquerque, New Mexico, raised its quarterly dividend from \$0.3275 to \$0.3475 and then to \$0.3575 per share. The increases are consistent with the company's target to pay out 55% of annual ongoing earnings. CenterPoint Energy, based in Houston, Texas, increased its quarterly dividend from \$0.17 to \$0.18 and then to \$0.19 per share. The increases align the company for an annual dividend growth rate of 9% in 2023 when compared to dividends paid in 2022. NextEra Energy,

2022 Dividend Patterns

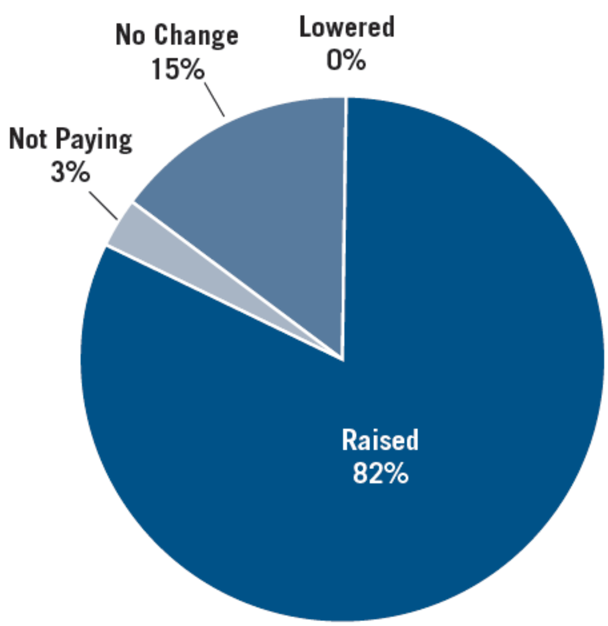
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department.

2021 Dividend Patterns

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department.

based in Juno Beach, Florida, increased its quarterly dividend from $0.385 to $0.425 per share. The increase is consistent with its plan, announced in 2020, to target roughly 10% annual growth in dividends per share through at least 2022, off a 2020 base. NextEra recorded the industry's highest percentage increases in 2021 (+10.0%), 2020 (+12.0%) and 2019 (+12.6%), which followed the second-highest percentage increase in 2018 (+13.0%) and the largest percentage increases in both 2017 (+12.9%) and 2016 (+13.0%, along with Edison International and DTE Energy).

PPL reduced its quarterly dividend from $0.415 to $0.20 in Q1 as part of a strategic repositioning and dividend reset. The company completed a targeted $1 billion share repurchase program on December 31, 2021, which returned value to existing shareholders in a different manner than dividends. During 2022, PPL completed the sale of its U.K. business (Western Power Distribution) and purchased Narragansett Electric Company, which is Rhode Island's primary electric and gas utility. PPL subsequently increased its dividend by 12.5% during Q2 2022 to a quarterly rate of $0.225 per share.

The industry's average and median increases have been relatively consistent in recent years. The average was 4.8% in 2021 and ranged between 5.1% and 5.7% from 2016 through 2020. The median increase was 5.4% in 2021 and ranged between 4.9% and 5.5% from 2017 through 2020.

Payout Ratio and Dividend Yield

The industry's dividend payout ratio was 73.0% for the twelve months ended December 31, 2022, exceeding all other U.S. business sectors. The industry's payout ratio was 70.8% when measured as an un-weighted average of individual company ratios; 73.0% represents an aggregate figure. From 2000 through 2021, the industry's annual payout ratio ranged from 60.4% to 69.6%.

While the industry's net income has fluctuated from year to year, its payout ratio has remained relatively consistent after eliminating non-recurring and extraordinary items from earnings. We use the following approach when calculating the industry's dividend payout ratio:

1. Non-recurring and extraordinary items are eliminated from earnings.
2. Companies with negative adjusted earnings are eliminated.

Sector Comparison Dividend Payout Ratio

For 12-month period ending 12/31/22

Sector	Payout Ratio (%)
EEI Index Companies*	**73.0%**
Utilities	59.3%
Consumer Staples	54.3%
Industrial	34.5%
Financial	29.1%
Materials	29.0%
Consumer Discretionary	27.6%
Energy	26.7%
Health Care	26.1%
Technology	23.0%

* For this table, EEI (1) sums dividends and (2) sums earnings of all index companies and then (3) divides to determine the comparable DPR.

Assumptions:
1. EEI Index Companies payout ratio based on LTM common dividends paid and income before nonrecurring and extraordinary items.

2. S&P sector payout ratios based on 2022E dividends and earnings per share (estimates as of 12/31/2022).

For more information on constituents of each S&P sector, see http://www.sectorspdr.com/.

Source: AltaVista Research, S&P Global Market Intelligence, and EEI Finance Department.

Sector Comparison, Dividend Yield
As of December 31, 2022

Sector	Dividend Yield (%)
EEI Index Companies	**3.4%**
Energy	3.2%
Utilities	3.0%
Consumer Staples	2.5%
Financial	2.1%
Materials	2.1%
Industrial	1.7%
Health Care	1.6%
Technology	1.1%
Consumer Discretionary	1.0%

Assumptions:
1. EEI Index Companies' yield based on last announced, annualized dividend rates (as of 12/31/2022); S&P sector yields based on 2022E cash dividends (estimates as of 12/31/2022).

For more information on constituents of each S&P sector, see http://www.sectorspdr.com/.

Source: AltaVista Research, S&P Global Market Intelligence and EEI Finance Department.

3. Companies with a payout ratio in excess of 200% are eliminated.

The industry's average dividend yield was 3.4% on December 31, 2022, leading all U.S. business sectors. The yield reached 3.8% on June 30, 2020 and has since fallen due to a rise in utility stock prices and consistent dividend activity. The market cap weighted EEI Index had a total return of 1.2% in 2022. The industry's year-end dividend yield was 3.3% in 2021, 3.6% in 2020, 3.0% in 2019 and 3.4% in each of the three previous years.

We calculate the industry's average dividend yield using an un-weighted average of the yields of EEI Index companies paying a dividend. The strong yields prevalent among most electric utilities have helped support their share prices over the past decade, particularly given the period's historically low interest rates.

Business Category Comparison

The Regulated category's dividend payout ratio was 69.2% for the 12 months ended December 31, 2022, compared to 77.4% for the Mostly Regulated category. The Regulated group produced the higher annual payout ratio in 2020, 2017, 2015, 2011, 2010 and in each year from 2003 through 2008.

The Regulated and Mostly Regulated average dividend yields were 3.4% and 3.3% on December 31, 2022, compared to 3.3% and 3.0% at year-end 2021, 3.6% and 3.4% at year-end 2020 and 3.0 and 3.1% at year-end 2019. The dividend yields for both categories at year-end 2018 and 2017 were 3.4%.

Electric Utilities' History of Strong Dividends

For more than a century, the investor-owned electric utility industry has stood out among U.S. business sectors for its steady and rising dividends. This reputation is founded on:

- A steady stream of income from a product that is universally needed with low elasticity of demand.
- A highly regulated industry that provides reasonable returns on investment with associated low business risk.
- A mature industry comprised of companies with very long track records of maintaining and/or steadily increasing their dividends over time.

These characteristics are especially attractive to an aging population of investors who seek a combination of growth and income. A typical total return model for electric utilities is approximately 4-5% annual earnings growth and a 3-4% dividend yield, producing a highly visible and relatively stable 7-9% annualized long-term total return potential.

Category Comparison, Dividend Payout Ratio

Category	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
EEI Index	**61.5**	**60.4**	**67.0**	**62.9**	**64.0**	**63.9**	**62.6**	**65.3**	**61.6**	**70.8**
Regulated	60.5	59.4	68.7	61.1	68.7	60.1	62.1	65.3	59.5	69.2
Mostly Regulated	64.7	63.8	62.6	68.0	53.3	72.8	64.1	65.2	69.0	77.4
Diversified	44.7	56.4	64.9	64.6	–	–	–	–	–	–

Regulated: 80% or more of total assets are regulated
Mostly Regulated: Less than 80% of total assets are regulated
Diversified: Prior to 2017, less than 50% of total assets are regulated

*2022 figures reflect earnings and dividends through 12/31/2022.

Source: S&P Global Market Intelligence, company reports, and EEI Finance Department

Category Comparison, Dividend Yield
As of December 31, 2022

Category	Dividend Yield
EEI Index	**3.4%**
Regulated	3.4%
Mostly Regulated	3.3%

Regulated: 80% or more of total assets are regulated
Mostly Regulated: Less than 80% of total assets are regulated
Source: S&P Global Market Intelligence, company reports and EEI Finance Department

The market's valuation of that return stream, of course, will shift with investor sentiment.

IRA Brings No Change to Dividend Tax Rate

An increase in dividend tax rates for the highest individual tax bracket was considered a potential revenue source for the Biden Administration's Build Back Better Act (BBBA) legislation until BBBA evolved into the passage of the Inflation Reduction Act of 2022 (IRA) in August. Due to the need to significantly reduce the size of this legislation in order to have a chance at success, the IRA passed as a slimmed down version of BBBA, retaining its robust clean energy tax package while maintaining current capital gains and dividend tax parity.

The top tax rate for dividends and capital gains is currently 20%, applying to 2022 income thresholds of $517,200 for couples and $459,750 for individuals. For taxpayers below these thresholds, dividends and capital gains are currently taxed at rates of 15% or 0%, depending on a filer's income. A 3.8% Medicare tax that was included in 2010 health care legislation is also applied to all investment income for couples earning more than $250,000 ($200,000 for singles).

Low dividend tax rates support the industry's ability to attract capital for investment. Maintaining parity between dividend and capital gains tax rates is crucial to avoid a disadvantage for companies that rely on a strong dividend to attract investors.

Dividend Summary
As of December 31, 2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Stock	Company Category	Annualized Dividends	Payout Ratio	Yield (%)	Last Action	To	From	Date Announced
ALLETE, Inc.	ALE	MR	$2.60	111.1%	4.0%	Raised	$2.60	$2.52	2022 Q1
Alliant Energy Corporation	LNT	R	$1.71	62.5%	3.1%	Raised	$1.71	$1.61	2022 Q1
Ameren Corporation	AEE	R	$2.36	56.5%	2.7%	Raised	$2.36	$2.20	2022 Q1
American Electric Power Company, Inc.	AEP	R	$3.32	67.3%	3.5%	Raised	$3.32	$3.12	2022 Q4
AVANGRID, Inc.	AGR	MR	$1.76	81.9%	4.1%	Raised	$1.76	$1.73	2018 Q3
Avista Corporation	AVA	R	$1.76	83.2%	4.0%	Raised	$1.76	$1.69	2022 Q1
Black Hills Corporation	BKH	R	$2.50	57.9%	3.6%	Raised	$2.50	$2.38	2022 Q4
CenterPoint Energy, Inc.	CNP	R	$0.76	NM	2.5%	Raised	$0.76	$0.72	2022 Q4
CMS Energy Corporation	CMS	R	$1.84	66.0%	2.9%	Raised	$1.84	$1.74	2022 Q1
Consolidated Edison, Inc.	ED	R	$3.16	59.4%	3.3%	Raised	$3.16	$3.10	2022 Q1
Dominion Resources, Inc.	D	R	$2.67	96.6%	4.4%	Raised	$2.67	$2.52	2022 Q1
DTE Energy Company	DTE	R	$3.81	66.8%	3.2%	Raised	$3.81	$3.54	2022 Q4
Duke Energy Corporation	DUK	R	$4.02	78.4%	3.9%	Raised	$4.02	$3.94	2022 Q3
Edison International	EIX	R	$2.95	43.6%	4.6%	Raised	$2.95	$2.80	2022 Q4
Entergy Corporation	ETR	R	$4.28	98.8%	3.8%	Raised	$4.28	$4.04	2022 Q4
Evergy, Inc.	EVRG	R	$2.45	69.3%	3.9%	Raised	$2.45	$2.29	2022 Q4
Eversource Energy	ES	R	$2.55	60.2%	3.0%	Raised	$2.55	$2.41	2022 Q1
Exelon Corporation	EXC	MR	$1.35	61.7%	3.1%	Raised	$1.35	N/A	2020 Q1
FirstEnergy Corp.	FE	R	$1.56	149.5%	3.7%	Raised	$1.56	$1.52	2019 Q4
Hawaiian Electric Industries, Inc.	HE	MR	$1.40	65.2%	3.3%	Raised	$1.40	$1.36	2022 Q1
IDACORP, Inc.	IDA	R	$3.16	59.4%	2.9%	Raised	$3.16	$3.00	2022 Q4
MDU Resources Group, Inc.	MDU	MR	$0.89	48.2%	2.9%	Raised	$0.89	$0.87	2022 Q4
MGE Energy, Inc.	MGEE	R	$1.63	51.8%	2.3%	Raised	$1.63	$1.55	2022 Q3
NextEra Energy, Inc.	NEE	MR	$1.70	98.6%	2.0%	Raised	$1.70	$1.54	2022 Q1
NiSource Inc.	NI	R	$0.94	55.5%	3.4%	Raised	$0.94	$0.88	2022 Q1
NorthWestern Corporation	NWE	R	$2.52	76.5%	4.2%	Raised	$2.52	$2.48	2022 Q1
OGE Energy Corp.	OGE	R	$1.66	NM	4.2%	Raised	$1.66	$1.64	2022 Q3
Otter Tail Corporation	OTTR	R	$1.65	24.2%	2.8%	Raised	$1.65	$1.56	2022 Q1
PG&E Corporation	PCG	R	$-	0.0%	0.0%	Lowered	$-	$2.12	2017 Q4
Pinnacle West Capital Corporation	PNW	R	$3.46	75.7%	4.6%	Raised	$3.46	$3.40	2022 Q4
PNM Resources, Inc.	PNM	R	$1.47	62.1%	3.0%	Raised	$1.47	$1.39	2022 Q4
Portland General Electric Company	POR	R	$1.81	67.8%	3.7%	Raised	$1.81	$1.72	2022 Q2
PPL Corporation	PPL	R	$0.90	110.2%	3.1%	Raised	$0.90	$0.80	2022 Q2
Public Service Enterprise Group Incorporated	PEG	MR	$2.16	74.9%	3.5%	Raised	$2.16	$2.04	2022 Q1
Sempra Energy	SRE	R	$4.58	56.5%	3.0%	Raised	$4.58	$4.40	2022 Q1
Southern Company	SO	R	$2.72	68.0%	3.8%	Raised	$2.72	$2.64	2022 Q2
Unitil Corporation	UTL	R	$1.56	60.6%	3.0%	Raised	$1.56	$1.52	2022 Q1
WEC Energy Group, Inc.	WEC	R	$2.91	63.5%	3.1%	Raised	$2.91	$2.71	2022 Q1
Xcel Energy Inc.	XEL	R	$1.95	58.3%	2.8%	Raised	$1.95	$1.83	2022 Q1
Industry Average				**70.8%**	**3.4%**				

NOTES

Business Segmentation: Assets as of 12/31/2021

R = Regulated: 80% or more of total assets are regulated. **MR = Mostly Regulated:** Less than 80% of total assets are regulated.

Dividend Per Share: Per share amounts are annualized declared figures as of 12/31/2022.

Dividend Payout Ratio: Dividends paid for 12 months ended 12/31/2022 divided by net income before nonrecurring and extraordinary items for 12 months ended 12/31/2022. While net income is after-tax, nonrecurring and extraordinary items are pre-tax, as there is no consistent method of gathering these items on a tax adjusted basis under current reporting guidelines. On an individual company basis, the Payout Ratio in the table could differ slightly from what is reported directly by the company.

"NM" applies to companies with negative earnings or payout ratios greater than 200%.

Dividend Yield: Annualized Dividends Per Share at 12/31/2022 divided by stock price at market close on 12/31/2022.

By Business Segment: Average of Dividend Payout Ratios and Dividend Yields for companies within these business segments.

Source: EEI Finance Department and S&P Global Market Intelligence.

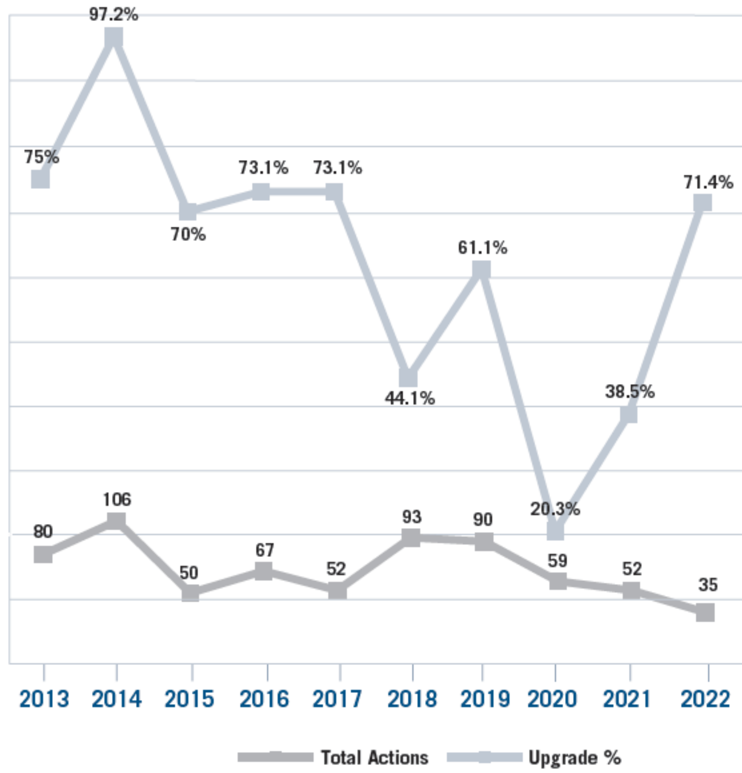
Credit Ratings

The industry's average parent company credit rating in 2022 remained at BBB+ for the ninth straight year, although one parent-level downgrade caused a slight weakening in aggregate holding company credit quality. There were only 35 total actions — 25 upgrades and 10 downgrades — affecting both parents and subsidiaries. This pace was far below the 73-action annual average of the previous ten calendar years and is the lowest annual total in our historical dataset (back to 2000).

On December 31, 2022, 77.3% of parent company ratings outlooks were "stable", 9.1% were "positive" or "watch-positive", and 2.3% were "developing". Only 11.4% of outlooks were "negative" or "watch-negative"; that was down from 22.7% at year-end 2021.

Direction of Rating Actions

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

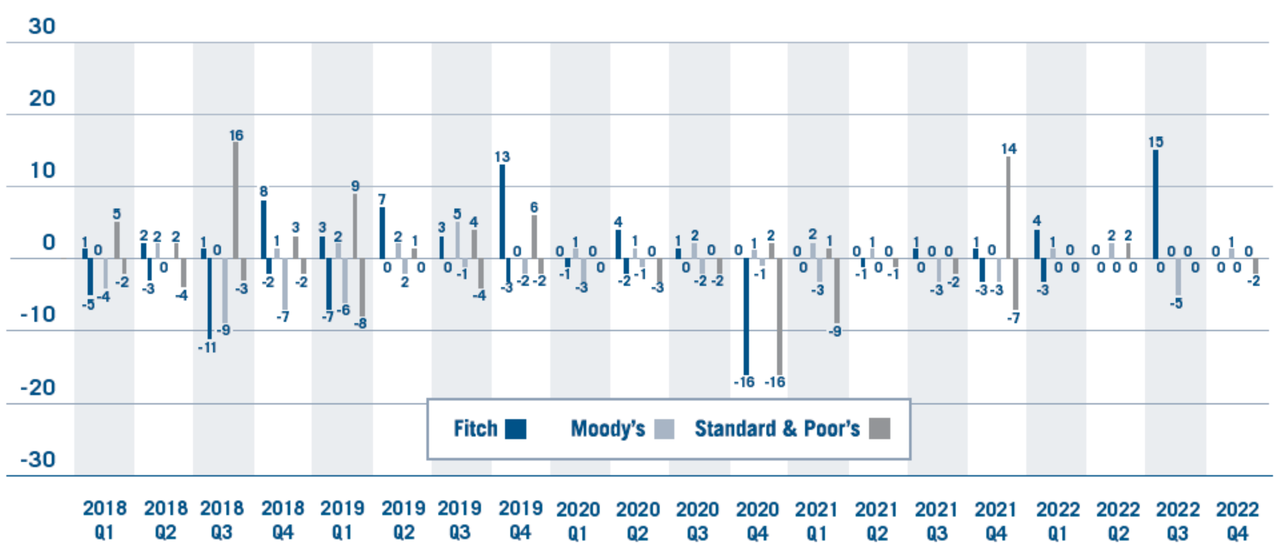


Source: Fitch Ratings, Moody's, and Standard & Poor's.

Credit Rating Agency Upgrades and Downgrades 2018 Q1–2022 Q4

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

(Number of Occurrences)



Note: Data presents the number of occurrences and includes each event, even if multiple actions occurred for a single company.

Source: Fitch Ratings, Moody's, and Standard & Poor's.

Credit Rating Agency Upgrades and Downgrades 2018 Q1–2022 Q4

	2018		2019		2020		2021		2022	
	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades
Fitch										
Q1	1	(5)	3	(7)	0	(1)	0	0	4	(3)
Q2	2	(3)	7	0	4	(2)	0	(1)	0	0
Q3	1	(11)	3	0	1	0	1	0	15	0
Q4	8	(2)	13	(3)	0	(16)	1	(3)	0	0
Total	**12**	**(21)**	**26**	**(10)**	**5**	**(19)**	**2**	**(4)**	**19**	**(3)**
Moody's										
Q1	0	(4)	2	(6)	1	(3)	2	(3)	1	0
Q2	2	0	2	(2)	1	(1)	1	0	2	0
Q3	0	(9)	5	(1)	2	(2)	0	(3)	0	(5)
Q4	1	(7)	0	(2)	1	(1)	0	(3)	1	0
Total	**3**	**(20)**	**9**	**(11)**	**5**	**(7)**	**3**	**(9)**	**4**	**(5)**
S&P										
Q1	5	(2)	9	(8)	0	0	1	(9)	0	0
Q2	2	(4)	1	0	0	(3)	0	(1)	2	0
Q3	16	(3)	4	(4)	0	(2)	0	(2)	0	0
Q4	7	0	3	(2)	2	(16)	14	(7)	0	(2)
Total	**17**	**(8)**	**26**	**(11)**	**2**	**(21)**	**15**	**(19)**	**2**	**(2)**

Note: Chart depicts the number of occurrences and includes each event, even if multiple downgrades occurred for a single company.
Source: Fitch Ratings, Moody's, and Standard & Poor's.

Electric utility industry credit quality generally improved over the past decade. The industry's average parent level rating has held at BBB+ since increasing from BBB in 2014. A closer look at the underlying calculation of this average shows a steady strengthening from 2013 through 2018, followed by a slight decline in 2019, 2020, 2021, and 2022. Across the larger universe that includes both parents and subsidiaries, the five-year period 2013 through 2017, along with 2022, produced the six highest upgrade percentages in our 23 years of historical data. Moreover, upgrades outnumbered downgrades in seven of the past ten calendar years with an annual average upgrade percentage of 62% over the decade.

EEI captures upgrades and downgrades at both the parent and subsidiary levels. The industry's average credit rating and outlook are the unweighted averages of all Standard & Poor's (S&P) parent holding company ratings and outlooks. However, our upgrade/downgrade totals reflect all actions by the three major ratings agencies including both parent holding companies as well as individual subsidiaries. Our universe of 44 U.S. parent company electric utilities on December 31, 2022 included 39 that are publicly traded and 5 that are either a subsidiary of an independent power producer, a subsidiary of a foreign owned company, or owned by an investment firm.

The three major rating agencies stressed similar themes in their outlooks for 2023. S&P maintained a negative outlook, Moody's revised its U.S. regulated utility outlook to negative from stable, and Fitch revised its North American utilities outlook to deteriorating from neutral. All three agencies cited higher natural gas prices, inflation, rising interest rates, and increased capital spending as key concerns. While the agencies noted regulatory relations are broadly constructive, all said that utilities' efforts to manage the regulatory risk associated with residential customer affordability issues will be a key area of scrutiny.

Credit Actions at Parent Level

Parent-level ratings actions in 2022 by S&P included only one downgrade. By comparison, there were three downgrades and one upgrade in 2021, three downgrades, one upgrade and one reinstatement in 2020, and five downgrades and one upgrade in 2019.

DPL

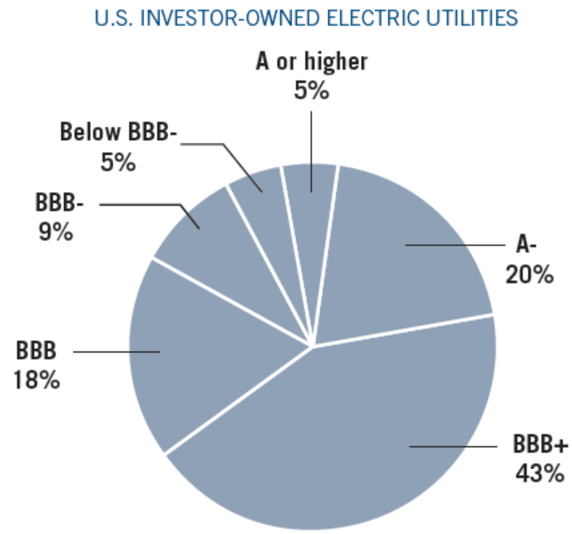
On December 21, S&P downgraded DPL Inc. and subsidiary Dayton Power and Light (DP&L) to BB from BB+. Dayton Power & Light received an order from the Public Utilities Commission of Ohio (PUCO) that authorized it to increase its distribution rates by $75 million. However, the increase will not go into effect until the company has a new Electric Security Plan (ESP) in place, which is not anticipated until mid-2023. S&P said the companies may be adversely impacted by cash flow pressures due to the delay.

Ratings Activity Remained Slow in 2022

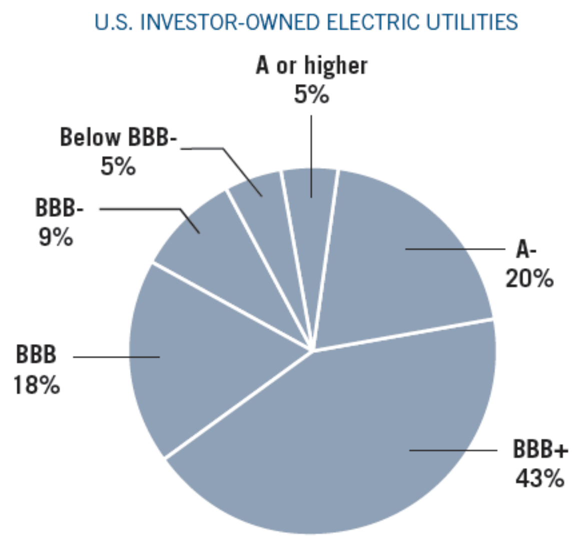
The 35 rating changes during 2022 (upgrades plus downgrades), 17 fewer than in 2021, was the lowest total of any year back to our dataset's inception in 2000. By comparison, there were 59 actions in 2020, 90 in 2019, and an annual average of 73 over the previous decade.

The industry's 25 upgrades in 2022 versus 10 downgrades produced an upgrade percentage of 71.4%, up from 38.5% in 2021 and 20.3% in 2020. Upgrades outnumbered downgrades in seven of the past ten calendar years, with an annual average upgrade percentage of 62%.

Bond Ratings December 31, 2022
as rated by Standard & Poor's

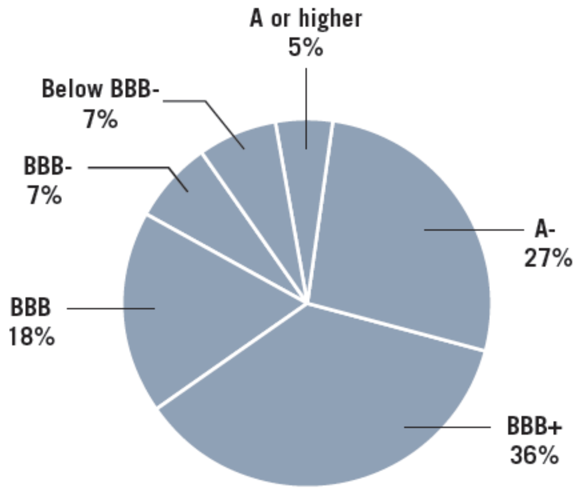


Bond Ratings December 31, 2021
as rated by Standard & Poor's



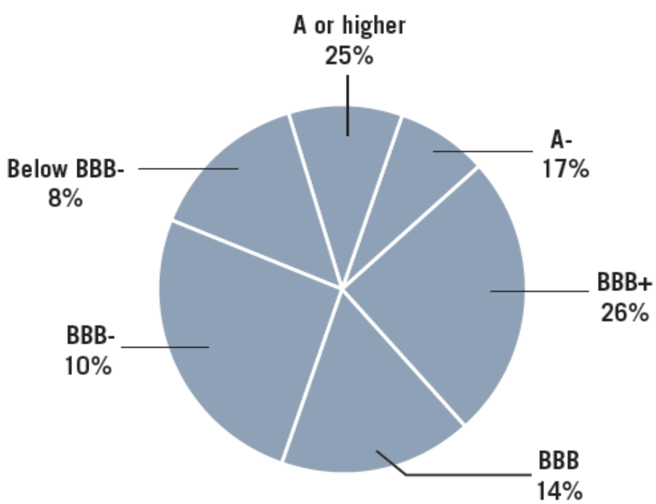
Bond Ratings December 31, 2020
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Bond Ratings December 31, 2001
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



The Credit Rating Agency Upgrades and Downgrades table presents quarterly activity by all three ratings agencies. Following are full-year totals for 2022:

- Fitch (19 upgrades, 3 downgrades)
- Moody's (4 upgrades, 5 downgrades)
- Standard & Poor's (2 upgrades, 2 downgrades)

Upgrades in 2022

Many of the year's upgrades came after favorable regulatory outcomes or strengthened financial metrics under new ownership. Upgrades were also driven by the use of asset sale proceeds to reduce parent company debt.

On January 14, Fitch upgraded Pepco Holdings, Pepco, and Atlantic City Electric to BBB+ from BBB due to improved credit profiles from supportive regulatory decisions.

On January 28, Moody's upgraded Entergy Texas to Baa2 from Baa3, following improved legislative and regulatory support. Moody's cited as reasons for the upgrade a recent authorization to securitize $250 million of storm costs, expedited cost recovery for a combined-cycle plant that recently began operations, and an upcoming rate case proceeding.

On March 30, Fitch upgraded Public Service Company of North Carolina (PSNC) to A- from BBB+ citing its strengthened financial condition as a result of equity contributions under Dominion's ownership since 2019 and a favorable re-

Rating Agency Activity

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Total Ratings Changes	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Fitch	23	14	11	16	15	33	36	24	6	22
Moody's	17	85	12	13	12	23	20	12	12	9
Standard & Poor's	40	7	27	38	25	37	34	23	34	4
Total	**80**	**106**	**50**	**67**	**52**	**93**	**90**	**59**	**52**	**35**

Source: Fitch Ratings, Moody's, Standard & Poor's, S&P Global Market Intelligence, and EEI Finance Department.

cent rate case outcome. The North Carolina commission approved a settlement with an ROE of 9.6% and equity capitalization of 51.6%. This was the first PSNC rate case under Dominion ownership. Fitch also cited strong service territory customer growth that support improved credit metrics.

On May 27, S&P upgraded PPL Electric Utilities (PPLEU), the Pennsylvania transmission and distribution subsidiary of PPL, to A from A-. The upgrade reflects S&P's view that PPLEU's financial performance, funding arrangements and operational independence are sufficient to support this rating.

On June 2, S&P Global Ratings raised the issuer credit rating of Narragansett Electric Co. (NECO) by one notch to A-. S&P cited the resolution of legal issues in Rhode Island that cleared the way for PPL to finalize its acquisition of Narragansett Electric. S&P assessed NECO's business risk profile as excellent due to supportive regulatory mechanisms in Rhode Island as well as electric transmission assets that benefit from a very supportive FERC regulatory framework.

On June 6, Moody's upgraded PPL Corporation to Baa1 from Baa2, based on its improved business risk profile; PPL reduced parent company debt by $3.5 billion using proceeds from the sale in 2021 of its U.K. utility business, Western Power Distribution, to National Grid for net cash proceeds of $10.4 billion. Moody's stable outlook reflects PPL's new business mix with its four U.S. utilities all operating in supportive regulatory environments. Moody's also upgraded Narragansett Electric Company to A3 from Baa1.

On July 22, Fitch upgraded FirstEnergy (FE) to BBB from BB+ based on FE's completed sale in May 2022 of a 20% ownership interest in FirstEnergy Transmission for $2.4 billion, FE's issuance of $1 billion of new equity, and a regulatory settlement in Ohio that provide rate certainty through May 2024. FirstEnergy used proceeds from its asset sales and equity issuance to pay down $2.4 billion of parent company debt. Fitch also raised the rating for fourteen subsidiaries.

On December 15, Moody's upgraded Dominion Energy South Carolina (DESC) to Baa1 from Baa2. The upgrade followed a series of rate orders by the South Carolina Public Service Commission (SCPSC) in 2022 that will help DESC recover higher costs, including under-recovered fuel balances, and improve cash flow. The SCPSC approved a settlement in December between DESC and various intervenors that provides $167 million of additional revenue to improve DESC's fuel cost recovery.

Downgrades in 2022

Many downgrades focused on increased debt and cash flow pressures that impacted credit metrics. The slow recovery of planned capital expenditures also drove several downgrades. Project delays related to a large nuclear project were cited also.

On January 14, Fitch downgraded Exelon to BBB from BBB+ due to higher leverage after the company's separation from its unregulated generation subsidiary, despite a resulting improved risk profile. Fitch observed that an expected equity issuance will not offset the loss of cash from the generation subsidiary and will result in increased parent debt.

On February 22, Fitch downgraded Georgia Power Company to BBB from BBB+ following an announced three- to six-month delay of the projected in-service dates for Vogtle nuclear units 3 and 4. The downgrade reflects continued uncertainty regarding the completion schedule and remaining costs for these nuclear generating facilities, with Georgia Power bearing a larger portion of cost increases under a 2018 modified co-owner agreement.

On March 24, Fitch downgraded NorthWestern Corporation to BBB from BBB+, primarily due to weaker credit metrics from expected regulatory lag during a period of extensive capital expenditures. The company's credit metrics are being pressured by a challenging regulatory framework, which is largely backward-looking, and a series of unfavorable rulings by the Montana commission that deny or delay recovery of expenses.

On July 6, Moody's downgraded IDACORP to Baa2 from Baa1 and subsidiary Idaho Power Company (IPC) to Baa1 from A3. Approximately 90% of IDACORP's cash flow is generated by IPC. Moody's observed that credit metrics would improve with more timely rate relief through riders or cost tracking mechanisms, quicker asset recovery via depreciation rates, and more frequent rate case filings. IPC's last rate increase under a general rate review occurred in 2011.

On August 22, Moody's downgraded AEP subsidiary Ohio Power Company to Baa1 from A3. Moody's cited weakened credit metrics from increased debt used to finance Ohio Power's significant investments in transmission and distribution infrastructure. Ohio Power's cash flow has also been negatively impacted by the expiration of legacy riders associated with the transition to competition in Ohio.

On September 13, Moody's downgraded the ratings of First Energy subsidiaries Cleveland Electric Illuminating Company (to Baa3 from Baa2) and Toledo Edison (to Baa2 from Baa1). Moody's said the companies will be adversely impacted by cash flow pressures caused by customer refunds stipulated in a 2021 regulatory settlement in Ohio. Both companies are expected to file rate cases by May 2024, when their current Electric Security Plans (ESP) expire.

Ratings by Company Category

The S&P Utility Credit Ratings Distribution by Company Category chart presents the distribution of credit ratings over time by company category (Regulated, Mostly Regulated and Diversified) for the investor-owned electric utilities. The Diversified category was eliminated in 2017 due to its dwindling number of companies. Ratings are based on S&P's long-term issuer ratings at the holding company level, with only one rating assigned per company. On December 31, 2022, the average rating for both the Regulated and Mostly Regulated categories was BBB+.

Rating Agency Credit Outlooks

The three major ratings agencies held similar utility industry credit outlooks as 2023 began. S&P maintained a negative outlook, Moody's revised its U.S. regulated utility outlook to negative from stable, and Fitch revised its North American utilities outlook to deteriorating from neutral. The agencies cited inflation, rising interest rates and higher natural gas prices and related customer bill impacts as key themes they are watching. It should be noted that the groups of underlying companies vary slightly across the three agency outlooks.

Standard & Poors (S&P)

Published in late January 2023, S&P's report "Industry Top Trends 2023 – North America Regulated Utilities" maintained the agency's negative industry outlook. The report noted that downgrades outpaced upgrades for the third consecutive year. While the percentage of negative outlooks decreased to 12% from 20% at year-end 2021, S&P stated that prolonged inflation or a deeper-than-expected recession could harm the industry's credit quality in 2023. Only 7% of the industry had a positive outlook.

S&P's base case assumes inflation will moderate during 2023 and the industry's credit measures will generally remain stable. However, persistent inflation could put additional pressure on customer bills and decrease regulatory support.

The report also cited potential risks related to the industry's aggressive reduction of greenhouse gas (GHG) emissions. S&P noted industry capital spending in 2022 reached an all-time high with an even higher total expected in 2023 with future investment focused on renewables and related infrastructure. As bills increase, regulators may

S&P Utility Credit Ratings Distribution by Company Category

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	2018		2019		2020		2021		2022	
	#	%	#	%	#	%	#	%	#	%
Regulated										
A or higher	1	3%	1	3%	1	3%	1	3%	1	3%
A-	11	32%	11	31%	11	32%	8	23%	8	22%
BBB+	11	32%	11	31%	10	29%	14	40%	15	42%
BBB	7	21%	8	23%	7	21%	7	20%	7	19%
BBB-	4	12%	2	6%	2	6%	3	9%	3	8%
Below BBB-	0	0%	2	6%	3	9%	2	6%	2	6%
Total	34	100%	35	100%	34	100%	35	100%	36	100%
Mostly Regulated										
A or higher	2	15%	1	10%	1	10%	1	11%	1	13%
A-	2	15%	1	10%	1	10%	1	11%	1	13%
BBB+	7	54%	7	70%	6	60%	5	56%	4	50%
BBB	1	8%	0	0%	1	10%	1	11%	1	13%
BBB-	1	8%	1	10%	1	10%	1	11%	1	13%
Below BBB-0	0	0%	0	0%	0	0%	0	0%	0	0%
Total	13	100%	10	100%	10	100%	9	100%	8	100%

Note: Totals may not equal 100.0% due to rounding.

Refer to page v for category descriptions.

Source: Standard & Poor's, S&P Global Market Intelligence, and EEI Finance Department.

ask the industry to slow the pace of the energy transition, possibly delaying the achievement of net-zero carbon emissions. In addition, large renewable projects (such as offshore wind) could become more challenging as timelines and budgets are affected by supply chain delays and rising interest rates. While much of the S&P report focused on the increased regulatory scrutiny that often accompanies higher customer bills, it also noted the average electric bill represents only about 2.5% of after-tax household income.

Moody's

In its "2023 Outlook – Regulated Electric and Gas Utilities – US" (released November 2022), Moody's revised its outlook for the sector to negative from stable. The report cited risks related to inflation, rising interest rates and higher natural gas prices as areas of concern. These developments could lead to customer affordability challenges and increased uncertainty related to the timely recovery of fuel and purchased power costs. The report also stated that capital spending and dividends will likely be sustained at a steady rate, possibly weighing on near-term credit metrics. The sector's aggregate industry funds from operations (FFO) to debt ratio will likely be 14% in 2023, according to the report, but may fall below this level if cost recovery is delayed.

Moody's listed several factors that could change its outlook back to stable: 1) if the sector's regulatory support remains intact, 2) if natural gas prices settle at a level that allows most utilities to fully recover fuel and purchased power costs within 12 months, 3) if inflation moderates and interest rates stabilize, and

Long-Term Credit Rating Scales

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Moody's	Standard & Poor's	Fitch
Investment Grade	Aaa	AAA	AAA
	Aa1	AA+	AA+
	Aa2	AA	AA
	Aa3	AA-	AA-
	A1	A+	A+
	A2	A	A
	A3	A-	A-
	Baa1	BBB+	BBB+
	Baa2	BBB	BBB
	Baa3	BBB-	BBB-

	Moody's	Standard & Poor's	Fitch
Speculative Grade	Ba1	BB+	BB+
	Ba2	BB	BB
	Ba3	BB-	BB-
	B1	B+	B+
	B2	B	B
	B3	B-	B-
	Caa1	CCC+	CCC+
	Caa2	CCC	CCC
	Caa3	CCC-	CCC-
	Ca	CC	CC
	C	C	C

	Moody's	Standard & Poor's	Fitch
Default	C	D	D

Source: Fitch Ratings, Moody's, and Standard & Poor's.

4) if the sector's aggregate FFO-to-debt ratio remains between 14% and 15%. Factors that could change its outlook to positive were: 1) if utility regulation turns broadly more credit supportive resulting in quicker cash flow recovery, and 2) if the sector's aggregate FFO-to-debt ratio rises above 17% on a sustained basis.

Fitch Ratings

In its "North American Utilities, Power & Gas Outlook 2023" (released December 2022), Fitch Ratings revised its outlook for the sector to deteriorating from neutral. The move primarily reflects growing cost pressures for utilities due to higher commodity prices, inflation, and rising interest rates. These factors, combined with high capital expenditures and storm restoration costs from extreme weather, are driving customer bills higher. Fitch noted that deferred fuel balances are increasing, which may affect credit metrics as utilities try to spread the recovery of these costs over an extended time period to mitigate the impact on customer bills.

The report also noted positive tailwinds that could offset these concerns. Retail electricity sales continue to show resilience and remain above pre-pandemic levels. Fitch expects authorized ROEs to start trending up in reaction to the recent rise in interest rates. Many utilities are increasingly using tools such as securitization for under-recovered fuel balances. The Inflation Reduction Act provides tax incentives for clean generation that may offset inflationary bill pressures. Finally, many companies are using asset monetization, such as the sale of non-regulated renewable businesses and the partial or full sale of regulated subsidiaries, to replace equity needs.

With 88% of companies at a stable ratings outlook, Fitch expects little ratings movement in 2023. The agency noted that higher-than-expected natural gas prices remains the largest risk to credit metrics since increases in deferred fuel balances can impair the timely recovery of capital expenditures.

Business Strategies

Business Segmentation

The industry's regulated business segments — regulated electric and natural gas distribution — grew their combined assets by $128.5 billion, or 7.8%, in 2022, extending a multi-year trend and driving a $78.2 billion, or 4.0%, increase in total industry assets. Regulated assets were 84.9% of the industry total at year-end, rising from 81.7% at year-end 2021. The Regulated Electric segment's share of total industry assets increased to 70.9% from 68.6% at year-end 2021 while the segment's total assets grew $98.8 billion, or 7.2%. Natural Gas Distribution assets rose $29.7 billion, or 11.4%, and Competitive Energy assets decreased $47.4 billion, or 22.7%. Assets for the Natural Gas Pipeline segment increased by $2.7 billion, or 8.2%. A record-high $147.7 billion of capital expenditures and generally constructive regulatory relations supported the significant growth in Regulated assets.

The Regulated Electric business segment's revenue increased by $38.3 billion, or 14.1%, as power demand rose 2.8% and inflationary pressures drove up fuel costs. Natural Gas Distribution revenue increased $14.0 billion, or 26.1%. Competitive Energy revenue decreased $14.3 billion, or 30.6%. Natural Gas Pipeline revenue increased by $1.0 billion, or 19.0%. Overall, total industry revenue increased $38.9 billion, or 10.1%, in 2022.

2022 Revenue by Segment

Regulated Electric revenue increased by $38.3 billion, or 14.1%, to $309.7 billion from $271.5 billion in 2021. The segment's share of total industry revenue rose to 71.3% from 68.4% in 2021, remaining well above its level at the start of the industry's two-decade-long migration back to a regulated focus (Regulated Electric's share was only 51.9% in 2005).

Business Segmentation—Revenues

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2022	2021r	Difference	% Change
Regulated Electric	309,739	271,451	38,288	14.1%
Competitive Energy	32,480	46,800	(14,320)	-30.6%
Natural Gas Distribution	67,426	53,469	13,957	26.1%
Natural Gas Pipeline	6,518	5,478	1,040	19.0%
Other	18,128	19,498	(1,370)	-7.0%
Discontinued Operations	—	—	—	0.0%
Eliminations/Reconciling Items	(9,863)	(11,197)	1,333	-11.9%
Total Revenues	**424,428**	**385,500**	**38,928**	**10.1%**

r = revised

Note: Difference and percent change columns may reflect rounding. Totals may reflect rounding.

Business Segmentation—Assets

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	12/31/2022	12/31/2021	Difference	% Change
Regulated Electric	1,476,245	1,377,457	98,788	7.2%
Competitive Energy	161,501	208,901	(47,400)	-22.7%
Natural Gas Distribution	291,443	261,706	29,736	11.4%
Natural Gas Pipeline	35,373	32,691	2,682	8.2%
Other	117,515	126,527	(9,012)	-7.1%
Discontinued Operations	1	1	-	0.0%
Eliminations/Reconciling Items	(63,257)	(66,629)	3,372	-5.1%
Total Assets	**2,018,820**	**1,940,653**	**78,167**	**4.0%**

r = revised

Note: Difference and percent change columns may reflect rounding. Totals may reflect rounding.

Natural Gas Distribution revenue rose $14.0 billion, or 26.1%, to $67.4 billion from $53.5 billion in 2021. This followed an increase of 18.0% in 2021, a decrease of 3.3% in 2020, and increases of 4.4% in 2019, 3.0% in 2018, 17.6% in 2017 and 8.9% in 2016; the sharp gains in 2016 and 2017 were due in part to the completion in 2016 of four large acquisitions of natural gas distribution businesses.

Total regulated revenue — the sum of the Regulated Electric and Natural Gas Distribution segments — increased by $52.2 billion, or 16.1%, to $377.2 billion in 2022. The industry's focus on regulated operations has driven a steady growth in these business segments' share of industry revenue in recent years. Regulated revenue accounted for 86.8% of total industry revenue in 2022 compared to 81.9% in 2021, totals well above 2005's 65.3% share.

Eliminations and reconciling items are added back to total revenue to arrive at the denominator for the segment percentage calculations shown in the graphs *Revenue Breakdown 2022 and 2021*.

2022 Assets by Segment

Regulated Electric assets increased $98.8 billion, or 7.2%, during 2022. The segment's share of total industry assets was 70.9% at year-end, above its 68.6% share at year-end 2021. Natural Gas Distribution assets increased by $29.7 billion, or 11.4%, while Competitive Energy assets decreased by $47.4 billion, or 22.7%. The Natural Gas Pipeline segment's relatively small asset total grew slightly, increasing by $2.7 billion, or 8.2%, to $35.4 billion at year-end 2022 and representing 1.7% of industry assets.

Total regulated assets (Regulated Electric and Natural Gas Distribution) grew $128.5 billion, or 7.8% in 2022, increasing their share of total industry assets to 84.9% at year-end from 81.7% at year-end 2021.

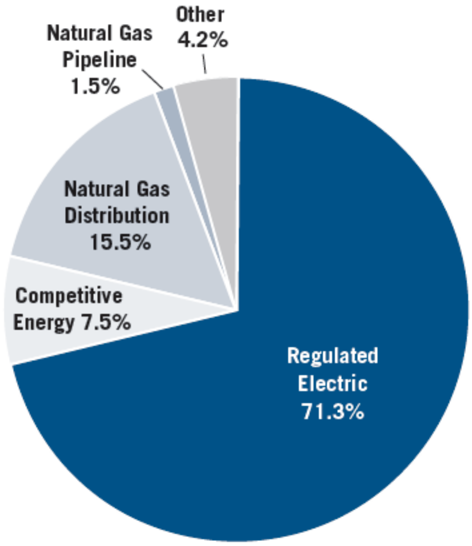
This aggregate measure has risen steadily from 61.6% at year-end 2002, underscoring the significant regulated rate base growth and widespread divestitures of non-core businesses over that 20-year period. Twenty-nine of the industry's 44 constituent companies (66%) either increased regulated assets as a percent of total assets or maintained a 100% regulated structure in 2022.

Regulated Electric

Regulated Electric segment operations include the generation, transmission and distribution of electricity under state regulation for residential, commercial and industrial custom-

Revenue Breakdown 2022

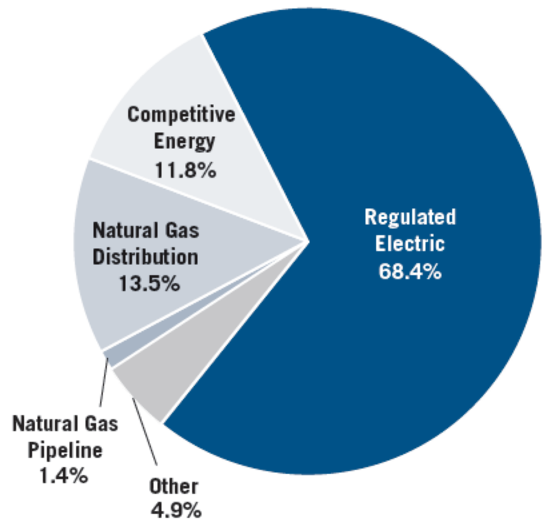
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

Revenue Breakdown 2021r

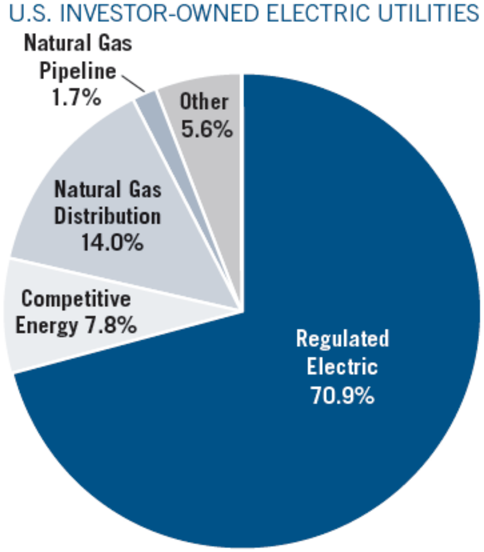
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

Asset Breakdown As of December 31, 2022

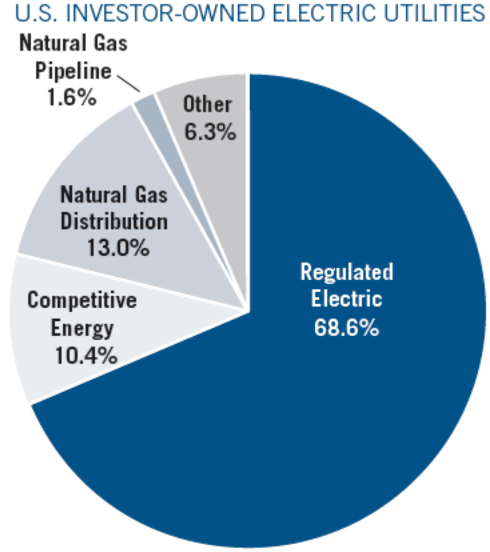
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

Asset Breakdown As of December 31, 2021

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

ers. Regulated Electric revenue increased significantly in 2022, rising $38.3 billion, or 14.1%. Forty-two companies, or 95% of the industry, had higher Regulated Electric revenue than the prior year. Regulated Electric revenue increased by 8.0% in 2021, fell by 0.8% in 2020 and by 0.5% in 2019, was unchanged in 2018, and grew by 0.8% in 2017.

Total nationwide electric output increased 2.8% in 2022, in line with a 2.8% increase in 2021. On a weather-adjusted basis, electric output rose 1.3% in 2022. Electric output has risen in only eight of the past fifteen years. Prior to this period, a year-to-year output decline was a rare event in an industry that typically experienced low-single-digit percent demand growth. Energy efficiency initiatives, demand-side management programs, and the off-shoring of formerly U.S.-based manufacturing and heavy industry are all forces that have suppressed the growth of electricity demand since the late 20th century.

Regulated Electric assets increased by $98.8 billion, or 7.2%, in 2022, representing the largest asset growth in dollar terms of all business segments. The industry's record-high $147.7 billion of capital expenditures in 2022 and generally constructive regulatory relations supported the increase in regulated assets. The 2022 capital expenditure total was the eleventh consecutive annual record high, with the expansion well represented across the industry's Regulated Electric and Natural Gas Distribution segments. Asset growth is also evident in the industry's net property, plant, and equipment in service, which rose 4.4% from year-end 2021 and 21.6% over the level at year-end 2018. Such robust growth in assets reflects the size of the industry's build-out of new renewable and clean generation, new transmission, reliability-related infrastructure, and other capital projects in recent years.

Competitive Energy

Competitive Energy assets decreased by $47.4 billion, or 22.7%, to $161.5 billion at year-end 2022 from $208.9 billion at year-end 2021. The large decrease was primarily driven by the spin-off of Constellation Energy, Exelon's power generation and competitive energy business, in February 2022. Competitive Energy revenue decreased by $14.3 billion, or 30.6%, to $32.5 billion from $46.8 billion in 2021. Competitive Energy covers the generation and/or sale of electricity in competitive markets, including both wholesale and retail transactions. Wholesale buyers are typically regional power pools, large industrial customers, and electric utilities looking to supplement generation capacity. Competitive Energy also includes the trading and marketing of natural gas. Of the 18 companies that maintain Competitive Energy operations, 11 (61%) grew these assets during 2022 and 16 (89%) had revenue gains from this segment.

Natural Gas

Natural Gas Distribution assets increased by $29.7 billion, or 11.4%, to $291.4 billion at year-end 2022 from $261.7 billion at year-end 2021. The segment's revenue increased by $14.0 billion, or 26.1%, to $67.4 billion from $53.5 billion in 2021. This followed revenue growth of 18.0% in 2021 and a revenue decline of 3.3% in 2020. All 27 companies that report gas distribution revenue showed a year-to-year increase in 2022, consistent with the identical 100% of reporting companies that did so in 2021. This followed increases at 26%, 70%, 86% and 93% of reporting companies in 2020, 2019, 2018 and 2017, respectfully. Natural Gas Distribution includes the delivery of natural gas to homes, businesses and industrial customers throughout the United States.

Natural Gas Pipeline assets increased by $2.7 billion, or 8.2%, to $35.4 billion at year-end 2022 from $32.7 billion at year-end 2021. Five of the six companies that report this segment showed asset growth. Higher natural gas prices enabled the segment's revenue to increase by $1.0 billion, or 19.0%, to $6.5 billion in 2022 from $5.5 billion in 2021. The Natural Gas Pipeline business concentrates on the transmission and storage of natural gas for local distribution companies, marketers and traders, electric power generators and natural gas producers.

Added together, the Natural Gas Distribution and Natural Gas Pipeline segments increased assets by $32.4 billion, or 11.0%, in 2022 and produced revenue of $73.9 billion, up from $58.9 billion in 2021. The contribution to total industry revenue from these two natural gas activities increased to 17.0% in 2022 from 14.9% in 2021.

Strategic Moves Completed in 2022

Several companies completed strategic transactions in 2022 that notably affected their business segmentation reporting.

- Exelon completed the separation of its regulated and competitive businesses into two publicly traded companies. Exelon said the separation gives each company the financial and strategic independence to focus on its specific customer needs while executing its core business strategy.
- PPL Corporation completed its acquisition of Rhode Island regulated utility Narragansett Electric Company from National Grid. PPL said the move finalized its strategic repositioning as a U.S.-focused energy company. The Narragansett Electric operations were renamed Rhode Island Energy.
- Public Service Enterprise Group (PSEG) completed the sale of its 6,750 MW portfolio of fossil generation units in New Jersey, Connecticut, Maryland, and New York to subsidiaries of ArcLight Energy Partners Fund. With this sale, PSEG concluded its transition to a 90% regulated company with a focus on clean energy and infrastructure investments.

Strategic Announcements in 2022

In addition to 2022's completed transactions, several announcements were made that, if completed, will impact business segment reporting in 2023 and beyond.

- Dominion Energy announced the sale of its West Virginia natural gas utility, Hope Gas (also called Dominion Energy West Virginia) for $690 million to an infrastructure fund owned by insurance company Ullico. The Ullico infrastructure fund said it would integrate Hope Gas with Hearthstone Utilities, a portfolio company that owns and operates gas utilities in Indiana, Maine, Montana, North Carolina, and Ohio.
- AEP said it would divest unregulated commercial renewables businesses over the next two years and focus on transmission and regulated renewable investments.
- Eversource announced it would look to exit its joint venture with Danish wind energy developer Orsted, which was formed to develop offshore wind in New England. Eversource said potential proceeds would support the strengthening, modernizing, and decarbonizing of its regulated energy assets.
- Con Edison announced it would sell its wholly owned commercial renewables subsidiary, Con Edison Clean Energy Businesses, to RWE Renewables Americas for $6.8 billion. Con Edison said it will focus on its core utility businesses and the investments needed to lead New York's ambitious clean energy transition.
- Duke Energy announced that it would sell its commercial renewable energy business in response to strong investor demand for renewable energy infrastructure. Duke said the sale of its wind and solar portfolio will help reduce debt and fund growth in its regulated businesses.

2022 Year-End List of Companies by Category

Early each calendar year, we update our list of investor-owned electric utility holding companies organized by business category. The list is based on the prior year-end business segmentation data presented in 10-Ks. Our two categories are Regulated (80% or more of holding company assets are regulated) and Mostly Regulated (less than 80% of holding company assets are regulated).

We use assets rather than revenue for determining category membership because we believe assets provide a clearer picture of strategic trends; fluctuating commodity prices for natural gas and power can impact revenue so greatly that a company's strategic approach to business segmentation may be distorted by reliance on revenue data alone. Comparing the list of companies from year to year reveals company migrations between categories and shows the general trend in industry business models. We also base our quarterly category financial data during the year on this list.

In 2022, Exelon and Public Service Enterprise Group moved from the Mostly Regulated to the Regulated category. Exelon's regulated asset percentage rose above 80% due to the spin-off of Constellation Energy, Exelon's former power generation and competitive energy business. The transaction was completed on February 1, 2022. Public Service Enterprise Group's regulated asset

List of Companies by Category at December 31, 2022

Regulated (38)

Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
Avista Corporation
Black Hills Corporation
CenterPoint Energy, Inc.
*Cleco Corporate Holdings LLC**
CMS Energy Corporation
Consolidated Edison, Inc.
Dominion Energy, Inc.
*DPL Inc.**
DTE Energy Company
Duke Energy Corporation
Edison International
Entergy Corporation
Evergy, Inc.
Eversource Energy
Exelon Corporation
FirstEnergy Corp.
IDACORP, Inc.
*IPALCO Enterprises, Inc.**
NiSource Inc.
NorthWestern Corporation
MGE Energy, Inc.
OGE Energy Corp.
Otter Tail Corporation
PG&E Corporation
Pinnacle West Capital Corporation
PNM Resources, Inc.
Portland General Electric Company
PPL Corporation
Public Service Enterprise Group Incorporated
*Puget Energy, Inc.**
Sempra Energy
Southern Company
Unitil Corporation
WEC Energy Group, Inc.
Xcel Energy Inc.

Mostly Regulated (6)

ALLETE, Inc.
AVANGRID, Inc.
*Berkshire Hathaway Energy**
Hawaiian Electric Industries, Inc.
MDU Resources Group, Inc.
NextEra Energy, Inc.

Note:* Non-publicly traded companies.

percentage rose above 80% with the sale of PSEG's fossil generation units in New Jersey, Connecticut, Maryland, and New York. These two changes increased the number of Regulated companies to 38 from 36 and reduced the Mostly Regulated group to six companies from eight.

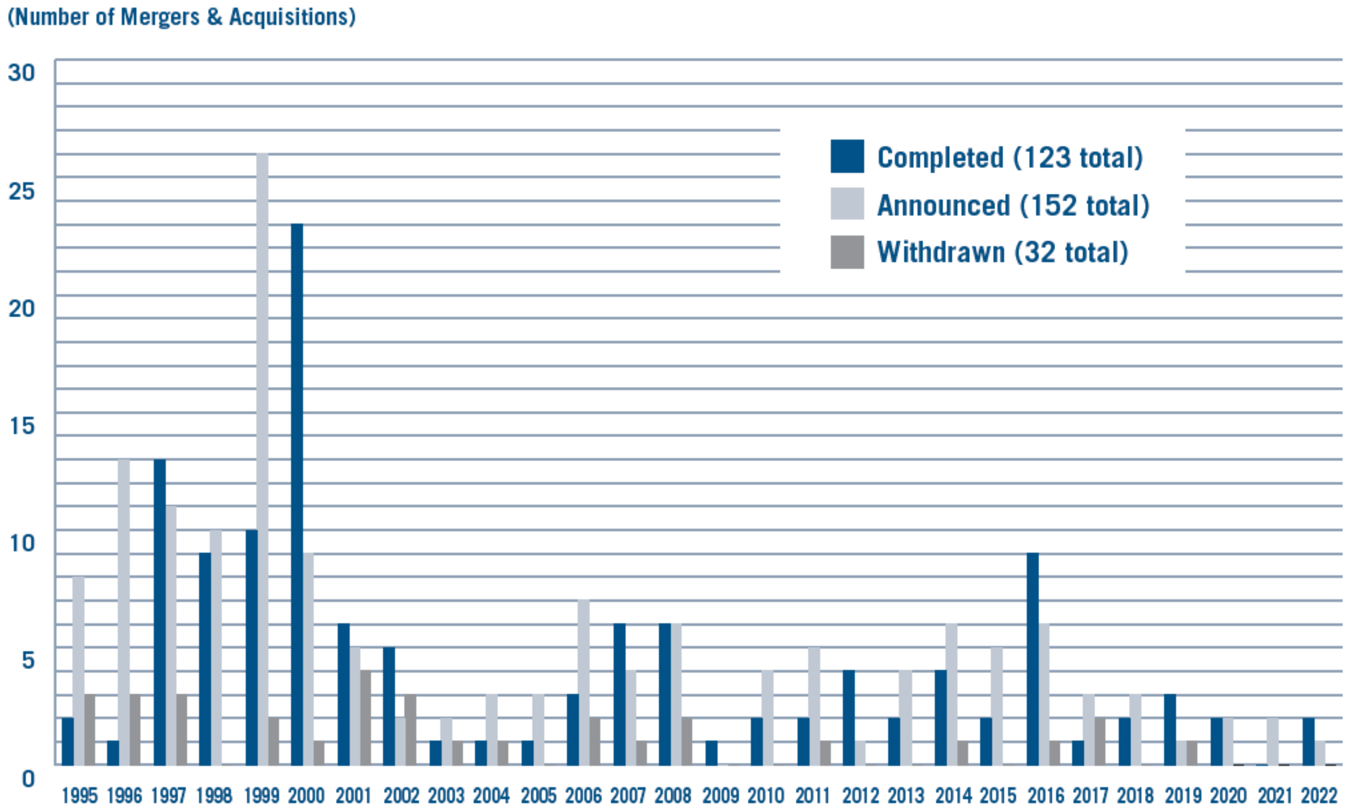
The number of parent companies in the EEI universe remained at 44, the same as the year-end 2021 total. (*See List of Companies by Category on December 31, 2022*).

Mergers & Acquisitions

Utility merger and acquisition (M&A) activity involving whole operating companies with regulated service territories remained quiet in 2022. The only new announcement was Dominion's move to sell its West Virginia natural gas utility, Hope Gas, to an infrastructure fund owned by insurance company Ullico. In fact, the year-end number of publicly traded utilities tracked by EEI was 39 for a third straight year. By contrast, consolidation from the mid-1990s through 2019 reduced the number of utility holding companies by more than half, from 98 to 40. The reduced number of holding companies alone constrains the opportunity set for new M&A. But industry fundamentals do as well. Most utilities are focused on ambitious investment programs that seek internal earnings and dividend growth through expansion of regulated rate base focused on clean energy infrastructure. The Inflation Reduction Act (IRA), passed in August 2022, provided a strong public policy tailwind for clean energy investment, which already was strongly incentivized by state renewable portfolio standards, carbon mitigation programs and overwhelming policy support for clean energy from state regulators and the general public. Most of the now-smaller group of utilities don't see M&A as a priority — particularly given the well-known challenges steering deals through a potentially complex state and federal regulatory approval process. These challenges were evident in two of the five deals announced since the end of 2019. AVANGRID's October 2020 bid to acquire New Mexico-based PNM Resources remained stalled during 2022 after New Mexico regulators

Status of Mergers & Acquisitions 1995–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department.

rejected the proposed transaction in late 2021. The sale of AEP's regulated subsidiary Kentucky Power to Liberty Utilities, a subsidiary of Canadian company Algonquin Power & Utilities, was blocked by the Federal Energy Regulatory Commission (FERC) in December 2022 due to concern over potentially higher transmission rates.

Infrastructure Fund to Buy Dominion's Hope Gas

On February 11, 2022, Dominion Energy announced it planned to sell its West Virginia natural gas utility, Hope Gas (also called Dominion Energy West Virginia) for $690 million to an infrastructure fund owned by insurance company Ullico Inc., which provides insurance services to union employees across the U.S. Ullico's infrastructure business said it would integrate Hope Gas with Hearthstone Utilities, a portfolio company that owns and operates gas utilities in Indiana, Maine, Montana, North Carolina, and Ohio. As part of the agreement, Hearthstone said it will move its headquarters to West Virginia. Ullico said that Hope Gas is an example of a core infrastructure business that provides essential services, creates high quality jobs, and is a stabilizing force in the West Virginia economy. It noted the acquisition is consistent with its investment philosophy that favors long-term ownership, responsible labor policies and a commitment to local economic development. The transaction was completed on September 1, 2022. The sale of Hope Gas follows Dominion's 2021 sale of Questar, a natural gas pipeline business, to Southwest Gas Holdings for $1.975 billion, including the assumption of $430 million of existing debt.

Status of Announced Mergers & Acquisitions 1995–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Year	Completed	Announced	Withdrawn
1995	2	8	3
1996	1	13	3
1997	13	11	3
1998	9	10	–
1999	10	26	2
2000	23	9	1
2001	6	5	4
2002	5	2	3
2003	1	2	1
2004	1	3	1
2005	1	3	–
2006	3	7	2
2007	6	4	1
2008	6	6	2
2009	1	–	–
2010	2	4	–
2011	2	5	1
2012	4	1	–
2013	2	4	–
2014	4	6	1
2015	2	5	–
2016	9	6	1
2017	1	3	2
2018	2	3	–
2019	3	1	1
2020	2	2	–
2021	–	2	–
2022	2	1	–
Totals	**123**	**152**	**32**

Source: EEI Finance Department.

PPL Completes Narraganset Electric Purchase

On May 25, 2022, PPL Corporation said it closed its acquisition of Rhode Island regulated utility Narragansett Electric Company, taking a little more than one year from the March 18, 2021 announcement date. Pennsylvania-based PPL Corporation announced in August 2020 it would seek to sell its U.K. utility distribution business, Western Power Distribution (WPD), and become a U.S. utility holding company focused on advancing the nation's clean energy goals with rate-regulated assets. That plan materialized in March 2021 when PPL announced an agreement to sell its

U.K. utility business, Western Power Distribution (WPD), to National Grid plc for £7.8 billion and, in a separate transaction, acquire National Grid's Rhode Island regulated utility business, The Narragansett Electric Company (NEC), for $3.8 billion. PPL said the strategic repositioning would refocus its strategy on strong, rate-regulated U.S. utilities, strengthen credit metrics and enhance long-term earnings growth and earnings predictability.

The agreement called for PPL to sell WPD to National Grid in an all-cash transaction valued at £14.4 billion, including assumption of £6.6 billion of debt, for net cash proceeds of approximately $10.2 billion. Separately, PPL planned to acquire Narragansett Electric from National Grid in a transaction valued at $5.3 billion, including the assumption of approximately $1.5 billion of Narragansett Electric debt. PPL said it planned to use a portion of the proceeds from the sale of WPD to finance the acquisition. PPL also highlighted its plan to play a key role in advancing Rhode Island's decarbonization goals, noting that its experience in automating electricity networks can help the state achieve its target of 100% renewable energy by 2030.

PPL said the closing of the Narragansett Electric acquisition completes its strategic repositioning as a U.S.-focused energy company. The Narragansett Electric operations were renamed Rhode Island Energy.

Two Recent Announcements Face Regulatory Headwinds

The sole 2020 announcement that made EEI's list of whole company deals was AVANGRID's offer to acquire PNM Resources. AVANGRID said the transaction would support its U.S. growth strategy focused on regulated businesses and renewables in states with legal and regulatory stability and predictability. PNM, which operates regulated utilities in Texas and New Mexico, called the move a strategic fit that will help the utility invest in clean energy distribution and transmission and expand its position in renewables.

Despite widespread stakeholder support and approvals by PNM shareholders, Texas regulators and the FERC, the New Mexico Public Regulation Commission rejected the merger on December 8, 2021. News reports cited concern about reliability, potential rate increases and slower development of renewable resources by PNM as reasons for the move. Reports also noted nearly all intervening customers and clean energy advocates supported the merger, and that the PRC staff had said they would not oppose it. AVANGRID expressed disappointment with the decision but said it will evaluate next steps and hoped the merger could eventually succeed.

The deal remained in limbo throughout 2022 after media reports said PNM and Avangrid had appealed the rejection to the New Mexico Supreme Court. In early 2023, news reports said the New Mexico Public Regulation Commission had joined PNM and AVANGRID in requesting the Supreme Court to send the case back to the commission for a "rehearing and reconsideration" following a move by the state's governor to replace the previous five-member commission with a new three-member body.

In the other announcement, AEP announced in April 2021 that it was conducting a strategic review of its Kentucky operations. On October 26, 2021, the company announced a sale, which included Kentucky Power and AEP Kentucky Transco, to Liberty Utilities, a regulated subsidiary of Canadian utility holding company Algonquin Power & Utilities. AEP said it plans to use the expected $1.45 billion cash proceeds to eliminate equity needs as it boosts investment in regulated renewable energy infrastructure. However, in December 2022 the FERC, which rarely rejects proposed utility mergers, said the companies failed to show the deal would not have an adverse effect on transmission rates. In February 2023, the two companies said they were committed to completing the sale and filed a revised application with FERC.

Exelon/Constellation Complete Separation

While not listed in the EEI mergers table, Exelon's move to separate its regulated and competitive businesses into two separate companies was a prominent industry event in 2021. The separation was completed on February 2, 2022. On February 24, 2021, Exelon announced a plan to split its six regulated utilities from its competitive power generation and customer-facing energy businesses, creating two publicly traded companies. Exelon said the separation gives each company the financial and strategic independence to focus on its specific customer needs while executing its core business strategy.

Exelon Corporation will continue as parent company for the fully regulated transmission and distribution utilities, which deliver electricity and natural gas to more than 10 million customers across five states and the District of Columbia. Constellation Energy Corporation will be the nation's largest supplier of clean energy with more than 31,000 megawatts of generating capacity consisting of nuclear, wind, solar, natural gas and hydro assets. Constellation will produce about 12 percent of the nation's carbon-free energy.

Exelon shareholders retained their shares of Exelon stock and received a pro-rata dividend of shares of Constellation. After the transaction closed on February 2, 2022, the regulated company retained the familiar EXC stock symbol while Constellation began trading under the symbol CEG.

Exelon noted the regulatory business is a high-quality utility asset with strong earnings growth of 6% to 8% annually and a diversified rate base across seven jurisdictions with constructive regulation. Exelon said the combination of strong operations and attractive ESG attributes provides a platform that supports transition to a clean energy economy without owning generation. The competitive business operates 18.7 gigawatts of nu-

Merger Impacts 1995–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Date	No. of Utilities	Change
12/31/95	98	–
12/31/96	98	–
12/31/97	91	(7.14%)
12/31/98	86	(5.49%)
12/31/99	83	(8.79%)
12/31/00	71	(14.46%)
12/31/01	69	(2.82%)
12/31/02	65	(5.80%)
12/31/03	65	–
12/31/04	65	–
12/31/05	65	–
12/31/06	64	(1.54%)
12/31/07	61	(4.69%)
12/31/08	59	(3.28%)
12/31/09	58	(1.69%)
12/31/10	56	(3.45%)
12/31/11	55	(1.79%)
12/31/12	51	(7.27%)
12/31/13	49	(3.92%)
12/31/14	48	(2.04%)
12/31/15	47	(2.08%)
12/31/16	44	(6.38%)
12/31/17	43	(2.27%)
12/31/18	42	(2.33%)
12/31/19	40	(4.76%)
12/31/20	39	(2.50%)
12/31/21	39	–
12/31/22	39	–

Number of Companies Declined by 60% since Dec.'95

Note: Based on completed mergers in the EEI Index group of electric utilities.

Source: EEI Finance Department.

clear generation and 12.3 gigawatts of natural gas, hydro, solar and wind energy. Constellation Energy also includes a retail business with a strong share of commercial and industrial energy customers in the nation's competitive energy markets.

Asset Sales Fund Regulated Clean Energy Capital Expenditures

Asset sales rather than merger activity seemed to be the focus of utility corporate strategies in 2022. Many utilities sold assets to finance ambitious investment programs focused on clean energy infrastructure, transmission and reliability investments, to eliminate the need to raise equity capital, to avoid or reduce debt, or to accomplish restructurings.

Duke Energy and ConEd both announced plans to sell commercial renewable energy subsidiaries in the face of strong investor demand for renewable energy infrastructure. Duke said the sale of its 5,100 MW wind and solar portfolio would help reduce debt and fund growth in its regulated businesses, and said it hoped to complete a transaction during 2023.

On October 1, 2022, ConEdison announced it would sell its wholly owned commercial renewables subsidiary, Con Edison Clean Energy Businesses, to RWE Renewables Americas for $6.8 billion. Con Edison said it would cancel plans to issue up to $850 million of common equity in 2022 and focus on its core utility businesses and the investments needed to lead New York's ambitious clean energy transition.

In February 2022, AEP said it would divest unregulated commercial renewables businesses over the next two years and focus on transmission and regulated renewable investments. In February 2023, AEP announced it agreed to sell its 1,365-megawatt (MW) unregulated, contracted renewables portfolio to IRG Acquisition Holdings, a partnership owned by Invenergy, CDPQ and funds managed by Blackstone Infrastructure, at an enterprise value of $1.5 billion including project debt.

And in May 2022, Eversource announced it would look to exit its joint venture with Danish wind energy developer Orsted, which was formed to develop offshore wind off the New England coast. Eversource said potential proceeds would support the strengthening, modernizing and decarbonizing of its regulated energy assets.

At year-end 2022, Wall Street research suggested that M&A discussions across the industry were focused on financial sponsors rather than strategic buyers. With most utilities focused on organic growth through regulated clean energy capital expenditures, it would appear that viable strategic M&A would have to advance that agenda while also offering tangible benefits to rate payers. The Inflation Reduction Act of 2022 along with strong policy support from state renewable portfolio standards has convinced most industry observers that the long-term growth opportunities inherent in the clean energy transition have a long way to run. Deals that create synergies and lower costs may succeed, but the diminished number of utilities makes those combinations rarer than they once were. An economic downturn and/or persistent inflation may change the calculus for some companies, who may decide going it alone no longer makes sense if a larger parent can help fund capital expenditures at a lower cost to customers. Yet utility M&A is inherently a highly political process, and it's hard to translate those truisms into confident predictions. About the only thing certain as 2023 commences is the inevitability of the clean energy revolution and utilities' front and center role making it happen.

Mergers & Acquisitions Announcements Updated through December 31, 2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Ann'cd	Buyer	Seller/Acquired/Merged	Status	New Company	Completed Date	Months to complete	Bus.	Terms	Est. Trans Value ($MM)
2/11/22	Ullico Inc.	Hope Gas, Inc.	Completed		8/31/22	6	EG	Ullico Inc. paid $690 million in cash to acquire Hope Gas Inc. (parent company Dominion Energy)	690.0
10/26/21	Algonquin Power & Utilities Corp	Kentucky Power Company & AEP Kentucky Transmission Company Inc	Pending				EE	$1.221 billion debt + $1.625 billion cash (valuation multiple of 1.3x rate base)	2,846.0
3/18/21	PPL Energy Holdings, LLC	Narragansett Electric Company	Completed		5/25/22	14	EG	$1.5 billion debt + 3.8 billion cash (valuation multiple of 1.7x rate base)	5,270.0
10/21/20	AVANGRID	PNM Resources	Pending				EE	AGR to pay $50.30/share in cash (roughly 10% premium) for PNM common stock	4,300.0
7/5/20	Berkshire Hathaway Energy	Dominion Energy Natural Gas Transportation and Storage	Completed		11/1/20	4	EG	$5.7 billion debt + $4.0 billion cash	9,700.0
6/3/19	JP Morgan Investment Management	El Paso Electric	Completed		7/29/20	13	EE	JPMorgan pays $68.25/share in cash for each share of El Paso Electric Co. common stock	4,285.7
5/21/18	NextEra Energy, Inc.	Gulf Power Company	Completed		1/1/19	7	EE	NEE to pay $4.35 billion in cash to acquire Gulf Power Company from Southern Company	4,350.0
4/23/18	CenterPoint Energy	Vectren Corporation	Completed		2/1/19	10	EG	CNP pays $72.00/share in cash for each share of Vectren common stock	6,000.0
1/3/18	Dominion Energy, Inc.	SCANA Corporation	Completed		1/1/19	12	EE	$6.7B debt + $7.9 stock (per share value of $55.35, roughly 31% premium)	14,600.0
8/21/17	Sempra Energy	Oncor Electric Delivery Co	Completed		3/8/18	6	EE	$9.5B cash	9,450.0
7/19/17	Hydro One Limited	Avista Corporation	Withdrawn		1/23/19			$5.3B cash (per share value of $53.00, roughly 24% premium)	5,300.0
7/7/17	Berkshire Hathaway Inc.	Oncor Electric Delivery Co	Withdrawn		8/21/17			$9.0B cash	9,000.0
9/28/16	DTE Energy	Appalachia Gathering System / Stonewall Gas Gathering	Completed		10/20/16	1	EG	Undisclosed	1,300.0
7/29/16	NextEra Energy, Inc.	Oncor Electric Delivery Co	Withdrawn		10/31/17			$6.8B debt + $4.4B cash	11,178.0
5/31/16	Great Plains Energy	Westar Resources	Completed	Evergy, Inc.	6/5/18	24	EE	$3.6B debt + $8.6 stock and cash (per share value of $60.00)	12,200.0
2/9/16	Fortis Inc.	ITC Holdings Corp.	Completed		10/14/16	8	EE	$4.4B debt + $6.9B common shares and cash (per share value of $44.90, roughly 33% premium)	11,300.0
2/9/16	Algonquin Power & Utilities	Empire District Electric Co	Completed		1/1/17	11	EE	$1.6B debt + additional debt and equity (per share value of $34.00, roughly 21% premium)	2,400.0
2/1/16	Dominion Resources, Inc.	Questar Corporation	Completed		9/16/16	8	EG	$1.5B debt + $2.4B cash + $500M equity (per share value of $25.00, roughly 30% premium)	4,400.0
10/26/15	Duke Energy	Piedmont Natural Gas	Completed		10/3/16	12	EG	$3.3B debt + $1.0B cash + $625M equity (per share value of $60.00, roughly 40% premium)	4,900.0
9/4/15	Emera	TECO Energy, Inc.	Completed		7/1/16	10	EE	$6.5B debt + $3.9B equity (per share value of $27.55, roughly 48% premium)	10,400.0
8/24/15	Southern Company	AGL Resources	Completed		7/1/16	10	EG	$4.1B debt + $8.0B equity (per share value of $66.00, roughly 36% premium)	12,060.4
7/12/15	Black Hills Corporation	SourceGas Holdings	Completed		2/12/16	10	GG	$760M debt + $1.13B cash	1,890.0
2/25/15	Iberdrola USA	UIL Holdings	Completed	AVANGRID, Inc.	12/16/15	10	EE	$1.8B debt + $0.6B cash + $2.4B equity (per share value of $52.75, roughly 25% premium, of which $10.50 will be cash)	4,756.0
12/3/14	NextEra Energy, Inc.	Hawaiian Electric	Withdrawn		7/18/16		EE	NEE to acquire HE for $2.6B equity + $1.4B debt (fixed exchange ratio of 0.2413 NEE shares)	3,963.0
10/20/14	Macquarie-led Consortium	Cleco	Completed		4/13/16	18	EE	$3.4B equity (all Cleco shares at $55.37 / share in cash (~15% premium)) + $1.3 debt	4,700.0
6/23/14	Wisconsin Energy	Integrys	Completed	WEC Energy Group	6/30/15	12	EE	WEC to acquire TEG for $5.758B equity + $3.374B debt (fixed exchange ratio of 1.128 WEC shares + $18.58)	9,100.0
5/1/14	Berkshire Hathaway Energy	AltaLink (Canadian)	Completed		12/1/14	7	ET	BHE to acquire AL for $3.2B cash + $2.7B debt	5,927.0
4/30/14	Exelon	Pepco	Completed		3/23/16	24	EE	EXC to acquire POM for $6.8B in cash ($27.25 per POM share)	12,337.0
3/3/14	UIL Holdings	Philadelphia Gas Works	Withdrawn		12/4/14		EG	UIL to acquire assets & liabilities of PGW from city of Philadelphia for $1.86 billion in cash	1,860.0
12/12/13	Fortis Inc.	UNS Energy	Completed		8/15/14	8	EE	Fortis pays $60.25 / share (31% premium to announcement day's close) + $1.8B in debt	4,578.1
11/4/13	Avista	Alaska Energy & Resources Company	Completed		7/1/14	8	EE	AVA to acquire Alaska Energy & Resources Company for $145MM equity + $24.5MM debt	169.5
5/29/13	MidAmerican Energy Holdings Co.	NV Energy	Completed	Berkshire Hathaway Energy	12/19/13	7	EE	MidAmerican pays $23.75 / share + assume $4.8 billion debt	10,494.3
5/25/13	TECO Energy, Inc.	New Mexico Gas Intermediate, Inc.	Completed		9/2/14	15	EE	TECO will pay $950 million, including assume $200 million debt to Continental Energy Systems LLC	950.0
2/20/12	Fortis Inc.	CH Energy Group	Completed		6/27/13	16	EE	Fortis pays $65.00/share cash & assumes approx. $687.37 MM debt.	1,609.7
5/27/11	Fortis Inc.	Central Vermont Public Service Corp	Withdrawn		7/11/11		EE	Fortis pays approx. $35.10/share cash & assumes approx. $226.4 mill in debt.	701.6
1/8/11	Duke Energy	Progress Energy	Completed		7/3/12	18	EE	0.87083 Duke shares (after 1-3 reverse split) for each Progress share + assume $12.1 billion net debt.	32,000.0
7/11/11	Gaz Metro LP	Central Vermont Public Service Corp	Completed		6/27/12	12	GE	Gaz Métro pays $35.25/share for each CVPS share & assumes $226 million debt.	704.2
10/16/10	Northeast Utilities	NSTAR	Completed		4/10/12	18	EE	1.312 NU shares for each NSTAR shr, plus $3.36 bill assume debt	7,566.7
4/28/11	Exelon Corp.	Constellation Energy Group Inc.	Completed		3/12/12	11	EE	CEG receive 0.93 shares of EXC for each CEG share. EXC assumes approx. $2.9 bill net debt	10,623.2
4/19/11	AES Corporation	DPL Inc.	Completed		11/28/11	7	EE	AES pays 30.00/share cash & assumes approx $1.1 billion of net debt	4,613.2
4/28/10	PPL Corp.	E.ON U.S.	Completed		11/1/10	6	EE	$6.83 billion cash + $764.0 million in assumed debt	7,625.0
3/12/10	Emera Inc	Maine & Maritimes	Completed		12/21/10	9	EE	$76 mm cash + $28.6 mm debt + $13.8mm postretirement benefits	117.4
2/10/10	FirstEnergy	Allegheny Energy	Completed		2/25/11	12	EE	$4.3 billion in equity + $4.7 billion in assumed debt	9,273.2
9/17/08	Berkshire Hathaway	Constellation Energy Group Inc.	Withdrawn		12/17/08		PE	$4.7 bill cash + $4.4 bill net debt and adjustments	9,152.5
7/25/08	Sempra Energy	EnergySouth Inc.	Completed		10/1/08	3	EG	$499 million cash + 283 million debt	771.9
7/1/08	MDU Resources Group, Inc.	Intermountain Gas Co.	Completed		10/1/08	3	EG	$245 million cash + $82 million debt	327.0

6/25/08	Duke Energy	Catamount Energy Corp.	Completed		9/15/08	3	EP	$240 million cash + $80 million assumed debt	320.0
2/15/08	Unitil Corp.	Northen Utilities / Granite State Gas Transmission	Completed		12/1/08	10	EG	$160 million cash	160.0
1/12/08	PNM Resources, Inc.	Cap Rock Holding Corp.	Withdrawn		7/22/08		EE	$202.5 million	202.5
10/26/07	Macquarie Consortium	Puget Energy	Completed		2/6/09	16	EE	$3.5 billion cash + $3.02 billion net debt	6,520.2
6/25/07	Iberdrola S.A.	Energy East Corp.	Completed		9/16/08	15	EE	$4.5 billion cash + $4.1 billion net debt	8,600.0
2/26/07	KKR & Texas Pacific Group	TXU Corp.[1]	Completed	Energy Future Holdings Corp.	10/10/07	8	PE	$31.8 billion cash + $12.1 billion net debt	43,882.0
2/7/07	Black Hills Corp. / Great Plains Energy Inc.[2]	Aquila Inc. (CO elec. util. + CO, KS, NE, IA gas utils.)	Completed		7/14/08	17	EG	$940 million cash +working capital and other adjustments	940.0
7/8/06	MDU Resources Group, Inc.	Cascade Natural Gas Corporation	Completed		7/2/07	12	EG	$305.2mm in cash + ($173.6 in debt - $13.0 in cash equivalents)	465.8
7/8/06	WPS Resources Corporation	Peoples Energy Corporation	Completed	Integrys Energy Group	2/21/07	7	EG	$2.47 billion	2,472.4
7/5/06	Macquarie Consortium	Duquesne Light Holdings	Completed		5/31/07	10	EE	$1.59 billion cash + $1.09 billion total debt	2,674.4
6/22/06	Gaz Metro LP	Green Mountain Power Corp.	Completed		4/12/07	10	EE	$187 million in cash + ($100.8 debt - $9.1mm in cash equivalents)	279.5
5/11/06	ITC Holdings Corp	Michigan Electric Transmission Co.	Completed		10/10/06	5	EE	$485.6mm cash + $70mm common stock + $311mm assumed debt	866.6
4/25/06	Babcock and Brown Infrastructure	NorthWestern Corp.	Withdrawn		7/24/07		EE	$2.2 billion cash	2,200.0
2/27/06	National Grid	KeySpan Corp.	Completed		8/24/07	18	EE	$7.4 billion cash + $4.5 billion long-term debt	11,877.5
12/19/05	FPL Group Inc.	Constellation Energy Inc.	Withdrawn		10/25/06		EE	$11.3 billion equity + $4.1 billion net debt and pension liabilities	15,311.5
5/24/05	MidAmerican Energy Holdings Co.	Pacificorp	Completed		3/21/06	10	EE	$5.1 billion cash + $4.3 billion in net debt and preferred stock	9,300.0
5/9/05	Duke Energy Corp.	Cinergy Corp.	Completed		4/3/06	11	EE	$9.1 billion equity + $5.5 billion net debt and pension liabilities	14,600.0
12/20/04	Exelon Corp.	Public Service Enterprise Group	Withdrawn		9/14/06		EE	$12.3 billion in equity + $13.4 billion in net debt and pension liabilities	25,700.0
7/25/04	PNM Resources	TNP Enterprises	Completed		6/6/05	12	EE	$189 million in stock and cash and $835 million in debt	1,024.0
2/3/04	Ameren Corp	Illinois Power[3]	Completed		10/1/04	8	EE	$1.9 billion in debt, pref stock, & other liab + $400 million in cash	2,300.0
11/24/03	Saguaro Utility Group L.P.	UniSource Energy	Withdrawn		12/30/04		PE	$850 million cash + $2 billion in debt	2,850.0
11/3/03	Exelon Corp.	Illinois Power	Withdrawn		11/22/03		EE	$275 million cash + $1.8 billion in debt + $150 million promissory note	2,225.0
4/30/02	Aquila Inc	Cogentrix Energy Inc	Withdrawn		8/2/02		EIPP	$415 million cash + $1.125 billion in assumed debt	1,540.0
4/29/02	Ameren Corp	CILCORP[4]	Completed		1/31/03	9	EE	$541 million cash + $781 in assumed debt + $41 million in pref stock	1,400.0
10/8/01	Northwest Natural Gas	Portland General	Withdrawn		5/16/02		GE	$1.55 billion cash + $250mm in stock	1,800.0
9/20/01	Duke Energy	Westcoast Energy	Completed		3/14/02	6	EG	Equity + cash valued at $27.90 per Westcoast share	8,500.0
9/10/01	Dominion Resources	Louis Dreyfus Natural Gas	Completed		11/1/01	2	EG	$890mm cash + $900mm stock +$505mm debt	2,295.0
2/20/01	Energy East	RGS Energy	Completed		6/28/02	16	EE	$1.4 bill. cash & equity + $1.0 bill. net debt	2,400.0
2/12/01	Pepco	Conectiv	Completed		8/1/02	18	EE	$2.2 bill cash & equity + $2.8 bill. net debt	5,000.0
11/9/00	PNM	Western Resources[5]	Withdrawn		1/8/02		EE	Stock transfer	4,442.0
10/2/00	NorthWestern	Montana Power[6]	Completed		2/15/02	16	EE	$1.1 billion in cash	1,100.0
9/5/00	National Grid Group	Niagara Mohawk	Completed		1/31/02	16	EE	$19 per share	8,900.0
8/8/00	FirstEnergy	GPU Inc.	Completed		11/7/01	15	EE	$35.60 per share	12,000.0
7/31/00	FPL Group	Entergy	Withdrawn		4/2/01		EE	1/1 - FPL, 0.585/1 - ETR	27,000.0
7/17/00	AES Corporation	IPALCO	Completed		3/27/01	8	IPPE	$25 per share	3,040.0
6/30/00	NS Power	Bangor Hydro	Completed	Emera	10/10/01	16	EE	$26.50 per share	206.0
5/30/00	WPS Resources	Wisconsin Fuel and Light	Completed		4/2/01	11	EG	1.73 shares of WPSR	55.0
2/28/00	PowerGen plc	LG&E	Completed		12/11/00	10	EE	$24.85 per share	5,400.0
8/8/00	FirstEnergy	GPU Inc.	Completed		11/7/01	15	EE	$35.60 per share	12,000.0
7/31/00	FPL Group	Entergy	Withdrawn		4/2/01		EE	1/1 - FPL, 0.585/1 - ETR	27,000.0
7/17/00	AES Corporation	IPALCO	Completed		3/27/01	8	IPPE	$25 per share	3,040.0
6/30/00	NS Power	Bangor Hydro	Completed	Emera	10/10/01	16	EE	$26.50 per share	206.0
5/30/00	WPS Resources	Wisconsin Fuel and Light	Completed		4/2/01	11	EG	1.73 shares of WPSR	55.0
2/28/00	PowerGen plc	LG&E	Completed		12/11/00	10	EE	$24.85 per share	5,400.0

1 TXU (now Energy Future Holdings Corp.) was acquired by the Texas Energy Future Holdings Limited Partnership (TEF) on 10/10/2007. TEF was formed by a group of investors led by Kohlberg Kravis Roberts and Texas Pacific Group to facilitate the merger.

2 Aquila was divided with Black Hills Corp. acquiring the electric utility in Colorado and NG utilities in CO, IA, KS, and NE. Great Plains Energy Inc. acquired the MI electric utility, stock, and other corporate assets.

3 Ameren purchased Illinois Power from Dynegy Corporation. Dynegy Corp acquired Illinois Power in February 2000.

4 Ameren purchased CILCORP from AES Corporation. AES Corp acquired CILCORP in October 1999.

5 PNM purchased Western Resources' electric operations including generation, transmission, and distribution.

6 NorthWestern Corporation purchased Montana Power's electric and natural gas transmission and distribution assets.

General Note: sum of Announced, Completed, Withdrawn, and Pending may not total due to inclusion of transactions announced prior to the 1994 window (e.g., a transaction announced in 1993 and completed in 1994 is included as a completion, but not as an announcement).

C = Completed	E = Electric
W = Withdrawn	G = Gas
PN = Pending	O = Oil
	IPP = Independent Power Producer
	P = Privatized

Source: EEI Finance Department, SNL Financial

Construction

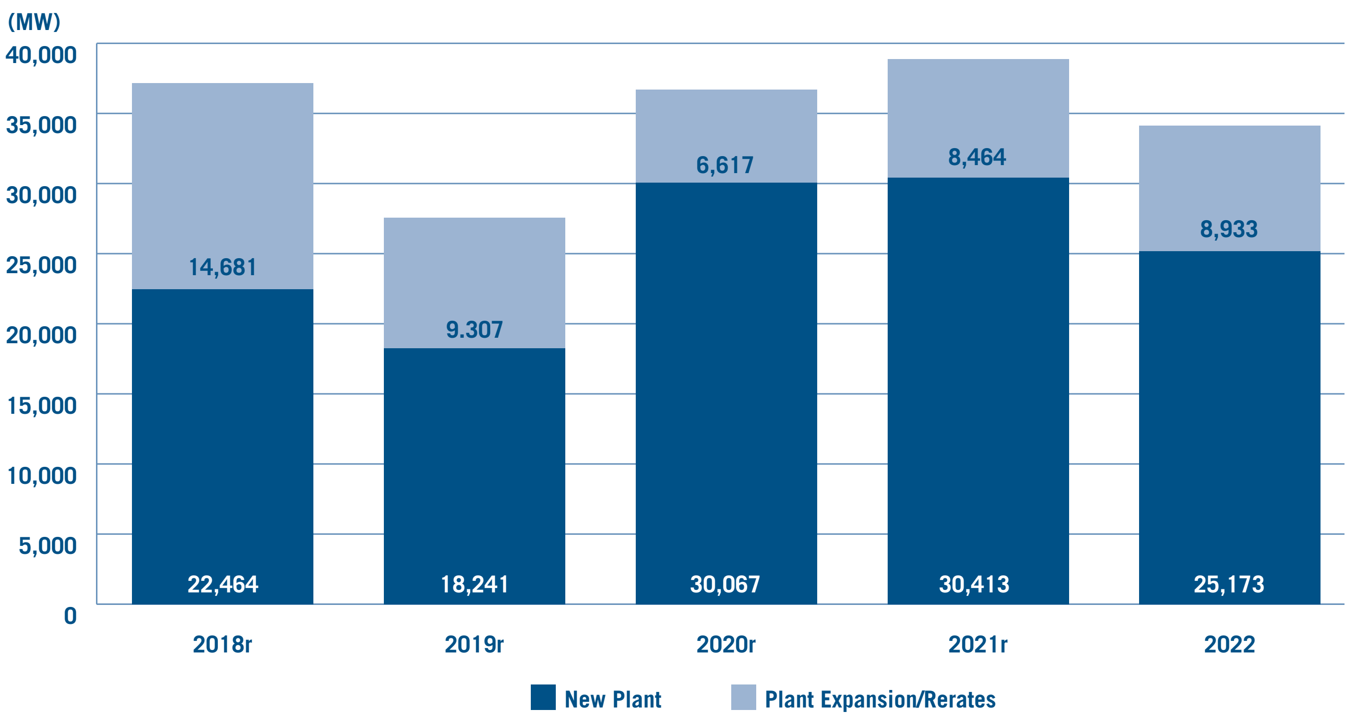
The electric utility industry brought 34,106 MW of new capacity online in 2022, 12% less than 2021's 38,877 MW and 7% less than the 36,684 MW of 2020. The decline from 2021 to 2022 was due to reductions in both solar and wind capacity. Supply chain issues continuously plagued wind and solar projects in 2022, causing many to be delayed. As a result, new wind capacity brought online decreased from 12,875 MW in 2021 to 10,148 MW in 2022. Solar capacity installation decreased 22%, from 15,370 MW in 2021 to 11,953 MW in 2022, marking the first annual decline for solar since 2018. Despite supply chain challenges, new natural gas capacity brought online increased from 6,924 MW in 2021 to 7,067 MW in 2022, marking natural gas's first annual increase since 2018.

New plants comprised 74% of 2022's total new capacity. Expansions and rerates accounted for the remaining 26%. The percentage of new plants slightly declined from 2021's rate of 78%.

Renewables continued to lead capacity additions, accounting for 65% of new capacity in 2022 versus 73% in 2021, even though supply chain challenges pushed some of 2022's scheduled projects into 2023. Supported by continually declining costs, wind and solar have powered more than half of the new capacity in each of the last four years. Solar led new capacity additions in 2022, accounting for 11,953 MW or 35% of the total across all fuels. Wind was second with 10,148 MW, or 30%. Investor-owned utilities that brought the most new renewable capacity online were NextEra Energy (2,682 MW of wind, 1,322 MW of solar), American Electric Power (999 MW of wind, 22 MW of solar), Duke Energy (207 MW of wind, 694 MW

New Capacity Online (MW) 2018–2022

U.S. ELECTRIC UTILITY AND NON-UTILITY



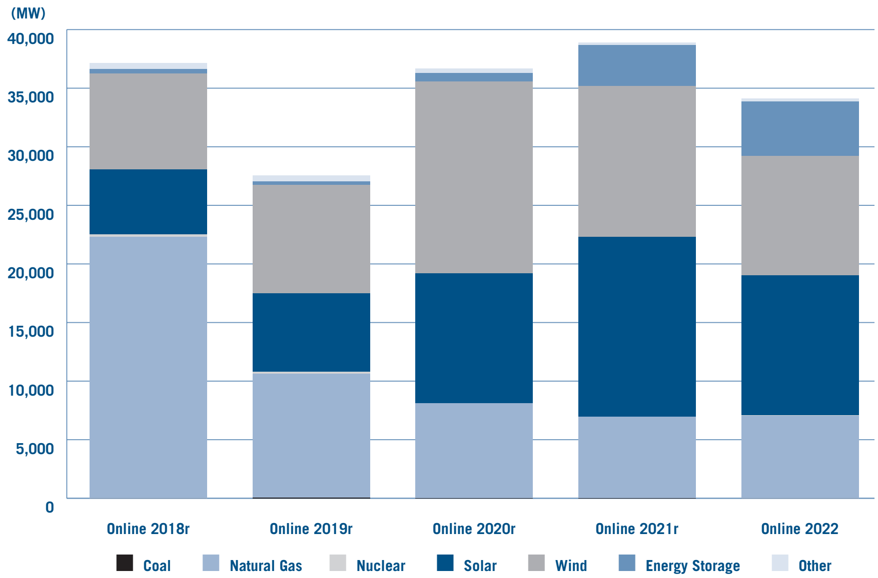
r = revised

Note: Includes all new capacity placed on the grid by U.S. investor-owned utilities, independent power producers, municipals, co-ops, government authorities and corporations. Totals may reflect rounding.

Source: The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2023

New Capacity Online by Fuel Type (MW) 2018–2022

U.S. ELECTRIC UTILITY AND NON-UTILITY



Fuel Type	2018r	2019r	2020r	2021r	2022
Coal	0	62	30	11	0
Natural Gas	22,320	10,549	8,078	6,924	7,067
Nuclear	192	175	20	0	17
Solar	5,542	6,714	11,083	15,370	11,953
Wind	8,187	9,232	16,343	12,875	10,148
Energy Storage	381	306	767	3,483	4,676
Other	524	510	362	215	246
Total	**37,145**	**27,548**	**36,684**	**38,877**	**34,106**

r = revised

Note: Includes all new capacity placed on the grid by U.S. investor-owned utilities, independent power producers, municipals, co-ops, government authorities and corporations. Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, and wood. Totals may reflect rounding.

The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2023

of solar), Xcel (322 MW of wind), AES (67 MW of wind, 252 MW of solar), ALLETE (304 MW of wind, 7 MW of solar), WEC Energy Group (300 MW of wind, 8 MW of solar), National Grid (275 MW of solar), Alliant Energy (254 MW of solar), and Ameren Corporation (202 MW of wind, 8 MW of solar).

Natural gas accounted for 21% of new capacity added in 2022; the year's 7,067 MW total was 2% higher than 2021's 6,924 MW. Combined cycle technology accounted for 78% of 2022's new natural gas capacity compared with 44% in 2021. Combustion turbines powered 20%. New plants represented 51% of the year's natural gas total, expansions accounted for 45% and the remaining 4% were rerates. DTE Energy led natural gas additions with 1,267 MW in new combined cycle gas plants, followed by NextEra Energy, whose gas turbine expansions totaled 1,163 MW. Third was Northwestern Corp. with 69 MW of new gas turbine capacity.

Energy storage accounted for nearly all the remaining 14% of new capacity added in 2022; a total of 4,676 MW was brought online, a 34% increase from 2021. Investor-owned utilities that brought the most energy storage capacity online included NextEra Energy (547 MW), AES Corporation (257 MW), PG&E Corporation (183 MW), and National Grid (125 MW).

New Capacity Online by Region

The Western Electricity Coordinating Council (WECC) brought the most capacity online of any region; WECC's 8,751 MW total for 2022 was 867 MW, or 11%, higher than 2021's 7,884 MW. An increase in new energy storage, from 1,993 MW to 2,992 MW, was the primary contributor to the gain. The Alaska Systems Coordinating Council (ASCC) also increased new capacity compared to 2021, rising from 9 MW in 2021 to 54 MW in 2022. The Hawaiian Coordinating Council (HCC) was the third and last region where new capacity brought online rose compared to 2021; new capacity in the HCC totaled 63 MW in 2021 and 81 MW in 2022. The year-to-year increase in HCC was driven by new solar additions, at 42 MW compared to 17 MW in 2021, which was slightly offset by a 7 MW decline in energy storage additions.

The SERC Reliability Corporation had the largest absolute decrease in new capacity added, from 8,054 MW in 2021 to 5,807 MW in 2022. The decline resulted from reduced additions of solar (4,746 MW to 3,834 MW), wind (887 MW to 121 MW), and energy storage (582 MW to 91 MW). New capacity added in The Electric Reliability Council of Texas (ERCOT) also declined more than 1,300 MW, falling 14% from

New Capacity Online by Region (MW) 2018–2022

U.S. ELECTRIC UTILITY AND NON-UTILITY

Region	Online 2018r	Online 2019r	Online 2020r	Online 2021r	Online 2022
ASCC	2	34	8	9	54
HCC	155	221	60	63	81
MRO	3,320	3,321	5,068	2,921	2,374
NPCC	3,386	2,267	1,693	1,566	1,038
RFC	11,980	4,047	2,783	6,150	5,175
SERC	9.577	7,322	8,970	8,054	5,807
SPP	1,922	1,142	3,366	2,740	2,705
TRE/ERCOT	2,935	5,312	5,997	9,490	8,121
WECC	3,868	3,883	8,739	7,884	8,751
Total	**37,145**	**27,548**	**36,684**	**38,877**	**34,106**

r = revised

Note: Data includes U.S. new plants, rerates, and expansions of existing plants, including nuclear uprates. Totals may reflect rounding.

Source: The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2023

Announced New Capacity by Region and Fuel Type in 2022 (MW)

U.S. ELECTRIC UTILITY AND NON-UTILITY

Fuel Type	Alaska Systems Coordinating Council	Reliability Council of Texas	Hawaiian Coordinating Council	Midwest Reliability Organization	Northeast Power Coordinating Council	Reliability First	SERC Reliability Corp	Southeast Power Pool Inc.	Western Electricity Coordinating Council
Coal	-	-	-	-	-	-	-	-	-
Natural Gas	-	361	-	132	-	65	780	-	-
Nuclear	-	-	-	-	-	-	-	-	-
Wind	-	-	-	1,212	2,209	1,046	763	453	5,801
Solar	-	4,622	79	2,271	4,029	5,222	11,854	1,065	7,947
Hydro	-	-	-	-	1	1	-	32	8
Energy Storage	-	5,306	157	344	8,477	162	518	-	7,560
Other	-	-	-	-	-	329	-	9	7
Total	**-**	**10,289**	**236**	**3,958**	**14,715**	**6,825**	**13,915**	**1,559**	**21,323**

r = revised

Notes: Data includes new plants and expansions of existing plants announced, including nuclear uprates. Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, and wood. Totals may reflect rounding.

Source: The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2023

Stage of Announced Capacity Additions (MW) 2023–2027

U.S. ELECTRIC UTILITY AND NON-UTILITY

Fuel	Proposed	Feasibility	Application Pending	Permitted	Site Prep	Under Construction	Testing	Total
Natural Gas	13,699	497	5,129	7,484	175	6,564	3,978	37,525
Nuclear	1,753	-	-	-	-	-	2,200	3,953
Solar	105,689	200	41,616	43,734	100	31,101	5,197	227,638
Wind	63,858	2,212	13,239	11,256	352	10,772	1,963	103,652
Energy Storage	41,368	8,971	27,634	13,537	-	8,657	953	101,121
Other	1,340	1,943	66	316	-	233	2	3,900
Grand Total	**227,707**	**13,823**	**87,684**	**76,327**	**627**	**57,328**	**14,292**	**477,789**

Notes: Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, hydroelectric turbines, and wood. Totals may reflect rounding. Data includes new plants and expansions of existing plants, including nuclear uprates. Data includes projects with an expected online date up to 2027.

Source: The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2023

9,490 MW in 2021 to 8,121 MW in 2022. That decline was led by lower solar (4,204 MW to 2,414 MW), gas (1,242 MW to 1,011 MW), and wind (3,393 MW to 3,332 MW) and was partially offset by an increase in energy storage capacity (641 MW to 1,364 MW).

Announcements by Region and Fuel Type

New capacity announced in 2022 totaled 72,819 MW, an increase of 43% over 2021's 51,032 MW. Renewable capacity accounted for 67% of 2022's total, with solar at 51%, wind at 16%, and hydro at 0.1%. Energy storage accounted for 31%. The remaining 2% was natural gas. As in 2021, no new coal or nuclear capacity was announced in 2022.

Energy storage produced the strongest year-to-year growth in announced new capacity with 22,522 MW announced in 2022. Northeast Power Coordinating Council (NPCC), Western Electricity Coordinating Council (WECC), and Electric Reliability Council of Texas (ERCOT) together accounted for 95%, or 21,342 MW, of the total new storage capacity announcements in 2022.

Higher wind and solar announcements also contributed to the growth in 2022 versus 2021. Announced new wind capacity increased 32%, from 8,668 MW in 2021 to 11,484 MW in 2022. New solar capacity announcements rose 6%, from 35,107 MW in 2021 to 37,089 MW in 2022. Federal government support for clean energy investment included in the Inflation Reduction Act (August 2022) and in the Infrastructure Investment and Jobs Act (November 2021) may have contributed to higher renewable capacity announcements in 2022 compared to 2021.

Announced new natural gas capacity decreased for the third year in a row, falling 56% from 3,060 MW in 2021 to 1,337 MW in 2022. Only four regions had new announcements: SERC Reliability Corporation (SERC), Electric Reliability Council of Texas (ERCOT), Midwest Reliability Organization (MRO), and Reliability First Corporation (RFC).

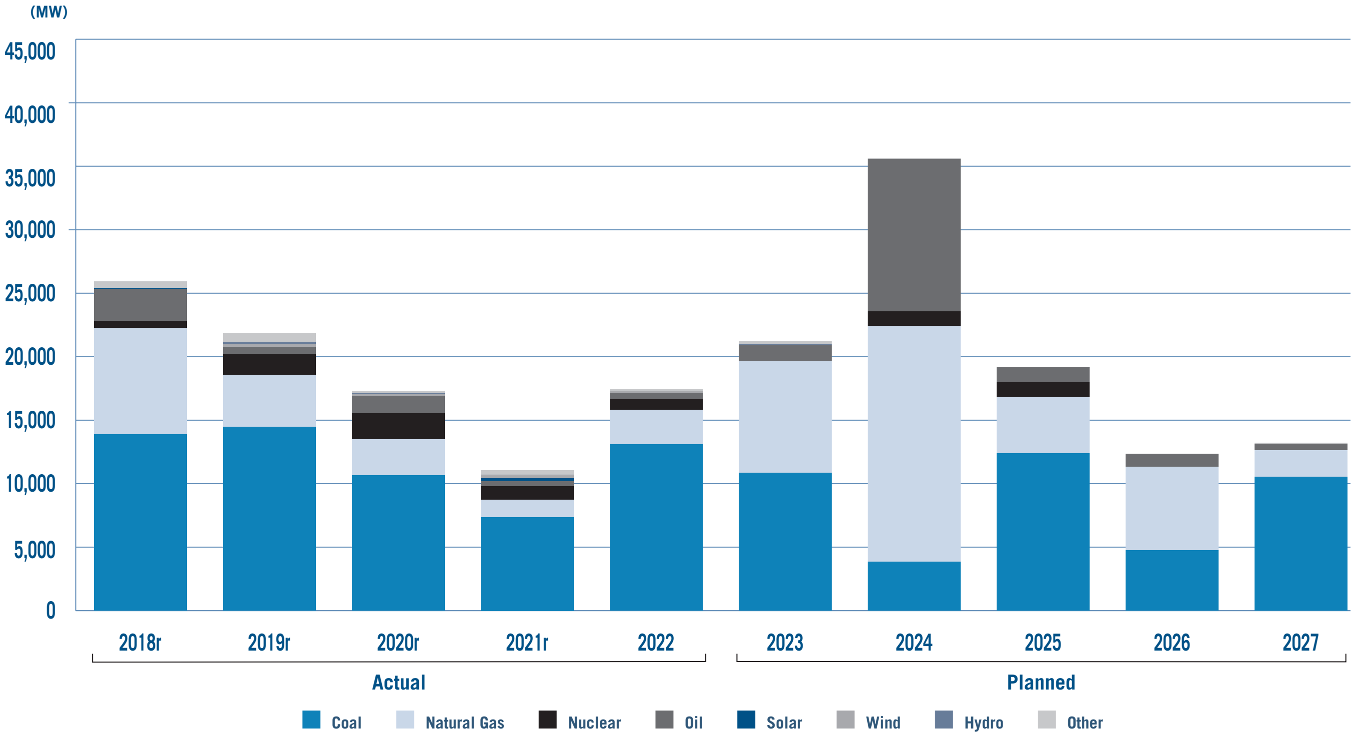
The Western Electricity Coordinating Council (WECC) saw the most announced new capacity of any region for the third year in a row, at 21,323 MW; 65% of that is renewable, with 37% solar, 27% wind, and less than 1% hydro. The remaining 35% is energy storage. The Northeast Power Coordinating Council (NPCC) region saw the second-highest amount of announced new capacity in 2022, at 14,715 MW; 58% is energy storage while the remaining 42% is renewable (27% solar and 15% wind).

Projected Capacity Additions

As of April 2023, new capacity expected to come online from 2023 through 2027 totaled 477,789 MW, a 31% increase over the comparable projection one year ago for the 2022 through 2026 five-year period. Renewable capacity accounted for most of the total, with solar representing 48% and wind accounting for 22%. The third-largest category was energy storage, at 21%, followed

Actual 2018-2022 and Projected 2023-2027 Retirements (MW)

U.S. ELECTRIC UTILITY AND NON-UTILITY



	Actual					Planned					
	2018r	2019r	2020r	2021r	2022	2023	2024	2025	2026	2027	Total
Coal	13,877	14,460	10,648	7,361	13,092	10,852	3,826	12,382	4,759	10,546	42,365
Natural Gas	8,400	4,110	2,853	1,357	2,720	8,804	18,593	4,418	6,574	2,092	40,482
Nuclear	550	1,641	2,031	1,074	823	-	1,159	1,164	-	-	2,323
Oil	2,483	546	1,337	383	476	1,232	11,993	1,191	1,004	488	15,908
Solar	3	8	-	275	2	-	-	-	1	4	5
Wind	63	208	229	235	168	41	-	1	-	-	43
Hydro	55	161	9	6	9	38	5	14	10	24	92
Other	481	738	211	379	126	283	67	1	-	50	401
Total	**25,910**	**21,872**	**17,318**	**11,070**	**17,415**	**21,250**	**35,644**	**19,171**	**12,348**	**13,204**	**101,617**

r = revised

Notes: Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, wood, and energy storage. Totals may reflect rounding. 2018-2022 is actual plants retired. 2023-2027 is projected based on announced or expected retirements.

Source: The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2023

by natural gas at 8% and nuclear at 1%. Natural gas and nuclear were 13% and 2%, respectively, of the 2022 through 2026 five-year total. Of the 477,789 MW total, 48% was in the proposal stage as of April 2023. Only 12% of the total was under construction and 3% was in the testing stage.

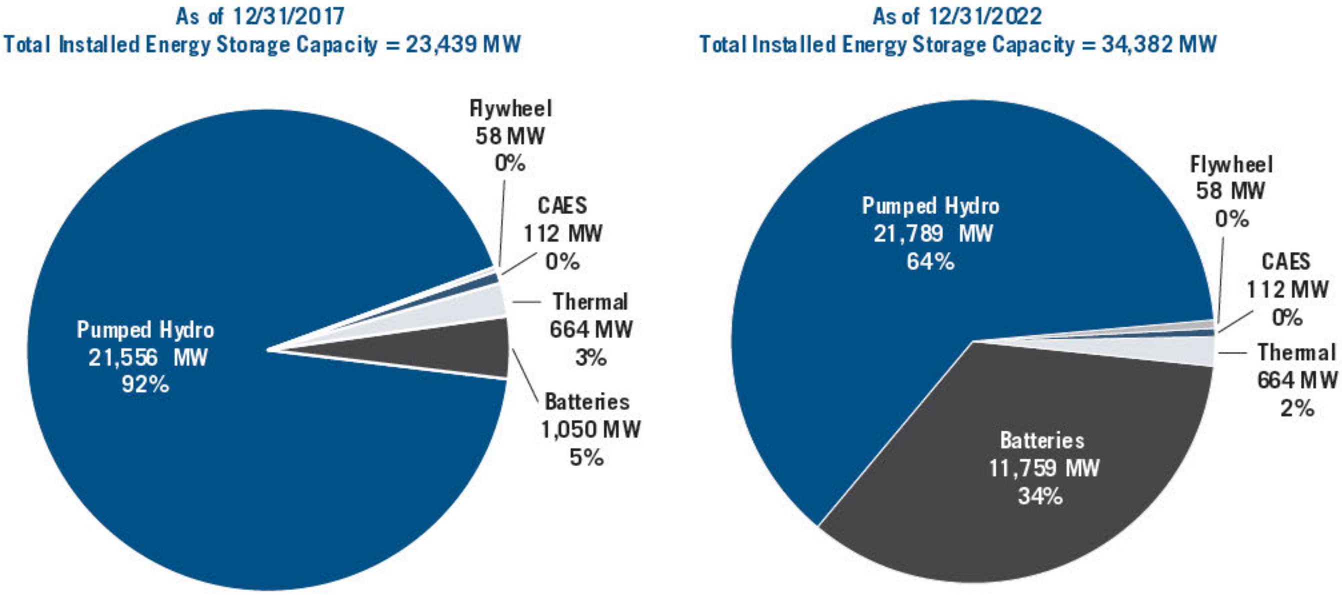
Retirements

As of April 2023, 101,617 MW of capacity was scheduled to be retired from 2023 through 2027. Coal continues to lead retirements, accounting for 42% of the projected total. Coal retirements are expected to reach 10,852 MW in 2023, a 17% decline compared to the actual 13,092 retirements in 2022. Natural gas ranked second and fuel oil third in terms of projected retirements over the full five-year period, at 40% and 16%, respectively.

Natural gas retirements are expected to peak in 2024 at 18,593 MW; this would be the highest actual or projected annual retirement total of any fuel from 2018 through 2027. Wind and solar retirements re-

Total Installed Energy Storage Capacity by Technology (MW)

U.S. ELECTRIC UTILITY AND NON-UTILITY



Sources: The Velocity Suite, Hitachi Energy; Wood Mackenzie Energy Storage Database; U.S. Department of Energy Sandia Energy Storage Dataset, EEI Energy Supply and Finance Department, March 2023

main minimal, together accounting for only a combined 0.05% of total projected retirements from 2023 through 2027. Nuclear retirements peaked in 2020, at 2,031 MW, with the shutdowns of the Duane Arnold Energy Center in Iowa (660 MW) and Indian Point Unit 2 in New York (1,371 MW). The Palisades Power Plant in Michigan (823 MW) was the only nuclear facility to retire in 2022 and accounted for all nuclear capacity retired. An additional 2,323 MW of nuclear capacity is expected to retire over the next three years due to the anticipated shutdown of the 2,323 MW Diablo Canyon Power Plant (CA) in stages between 2024 and 2025.

Energy Storage

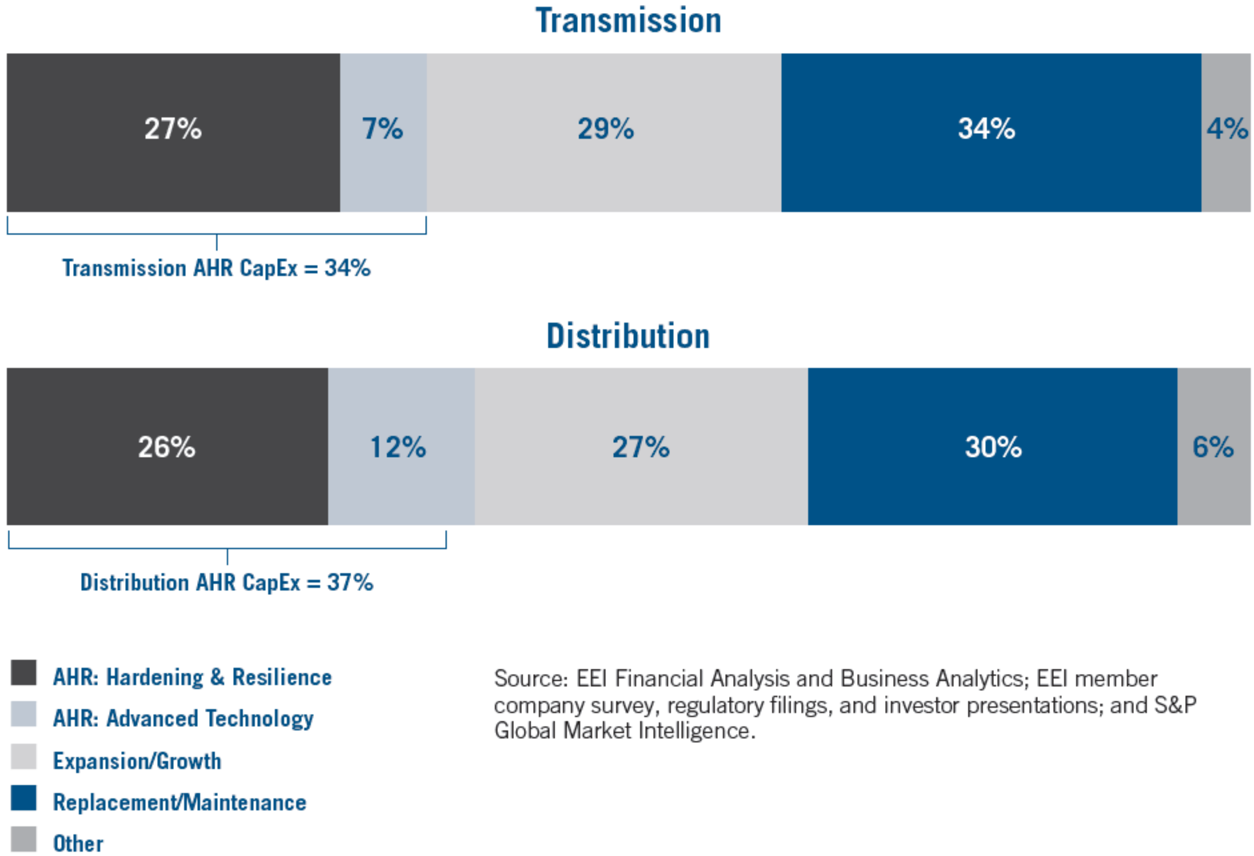
Energy storage continues to be a fast-growing area for the industry. At year-end 2022, utilities owned or operated 31,883 MW of storage capacity, or about 93% of all energy storage in the United States. Since 2017, total installed energy storage capacity nationwide owned or operated by utilities has increased 38%, from about 23,127 MW in 2017 to 31,883 MW in 2022.

Pumped hydro accounted for 68% of the total energy storage capacity owned by both U.S. investor-owned utilities and non-utilities, at 21,789 MW of capacity. Battery storage is the fastest-growing storage technology in terms of capacity, with total deployed capacity up approximately 1,020% from 2017 to 2022. Between 2017 and 2022, battery energy storage grew from 5% of total energy storage capacity to 34%.

The fast-paced growth of battery storage is likely to continue; 74,271 MW of battery storage capacity is expected to come online from 2023 through 2027, representing 83% of all incremental energy storage during this time period and becoming the dominant energy storage technology. Utilities will continue to lead battery storage deployment, accounting for 60,503 MW of the projected new battery storage capacity from 2023 through 2027.

Pumped hydro accounts for 16% of projected energy storage deployment from 2023 through 2027. Four rerate projects result in 267 MW capacity – Bear Swamp in Massachusetts (33 MW), Bad Creek

Adaptation, Hardening, and Resilience (AHR) as Drivers of T&D Investment
Based on 2022 Survey Results



Source: EEI Financial Analysis and Business Analytics; EEI member company survey, regulatory filings, and investor presentations; and S&P Global Market Intelligence.

in South Carolina (173 MW), Salina in Oklahoma (24 MW), and Cabin Creek in Colorado (37 MW). Two expansion projects account for 1,260 MW capacity – the Mineville Pumped Storage Project in New York (260 MW) and the Swan Lake North Hydro Pumped Storage Project (1,000 MW). The remaining announced projects are new constructions in the early stages of development.

The remaining 1% of new energy storage is compressed air energy storage at one project, the Rosamond CASE project in California at 500 MW. The project is expected to come online in 2024.

Transmission and Distribution

EEI member companies are spending a significant and growing amount of resources on adaptation, hardening, and resilience (AHR) initiatives. In recent years, it is estimated that EEI's member companies have invested almost $30 billion per year in AHR for transmission and distribution infrastructure. Specific examples of AHR investments in the electric grid include undergrounding power lines, installing cement poles, and elevating or relocating transformers. AHR is increasingly becoming an important way for electric companies to fulfill their mission of supplying customers with reliable, affordable, and increasingly sustainable energy. Electric companies also are developing weather predictive services, risk modeling, fire spread modeling, deployment of sensors and high-definition cameras, communication networks, satellite data damage assessment, and other real or near real time situational awareness instruments that can help them better predict and prepare for extreme weather events and wildfires.

Fuel Sources

Net Generation and Electricity Sales

Electric power industry net generation in 2022 totaled 4,301,648 gigawatt hours (GWh), an increase of 3.5% versus 2021. Nationwide retail electricity sales increased 2.7%, showing gains across 45 states and the District of Columbia and rising for the second consecutive year after last year's 2.1% increase. The states with the largest year-to-year percentage increases in retail electricity sales in 2022 were North Dakota (+10.7%), New Mexico (+8.5%), Florida (+7.4%), and Oklahoma (+7.4%). Oregon (-1.3%), New Hampshire (-0.5%), Minnesota (-0.2%), Connecticut (-0.2%), and Massachusetts (-0.1%) were the few states where sales declined.

Total sales to commercial customers increased 3.4%, substantially above the 2.7% overall nationwide sales gain. This is the second consecutive annual increase for commercial sales after last year's 2.9% growth, indicating that business activity has continuously returned to normal following 2020's pandemic-related shutdowns. Almost every state experienced growth in commercial sales in 2022, with North Dakota (+10.7%) experiencing the largest percentage gain. The only states showing a decline were Connecticut (-1.5%) and New Hampshire (-0.6%).

Total electricity sales to industrial customers increased 0.7% year-to-year, producing gains in 31 states. The 2022 percentage increase was lower than 2021's 2.9%, which was likely driven by resumption and expansion of industrial activity after states relaxed their COVID-19 protocols. New Mexico (+15.2%) and Florida (+12.8%) had the highest percentage increases. While the District of Columbia produced the largest percentage increase in 2021, at 29%, it saw the largest percentage decrease in 2022, at -24.2%. Louisiana showed the largest sales gain in absolute terms, at 2,552 GWh, representing a 6.7% increase over 2021's total. Nineteen states – Alabama, California, Delaware, Idaho, Indiana, Kentucky, Maine, Minnesota, New Hampshire, New Jersey, New York, Oregon, Rhode Island, South Dakota, Texas, Utah, Vermont, Virginia, Washington – and the District of Columbia all experienced lower industrial sales compared to 2021's total; decreases ranged from 0.1% (Idaho) to 24.2% (District of Columbia).

Electricity sales to residential customers increased 3.5% in 2022, above last year's 0.8% gain. Texas (+10.7%) and North Dakota (+8.2%) were the states with the highest percentage growth in 2022. Texas also experienced the largest growth in absolute terms, at 16,583 GWh, followed by Florida, at 9,066 GWh. Forty-

Fuel Sources for Net Electric Generation

U.S. ELECTRIC UTILITY AND NON-UTILITY

	2021r	2022
Coal	21.6%	19.3%
Gas	38.0%	39.3%
Nuclear	18.7%	17.9%
Hydro	6.1%	6.1%
Renewables	14.7%	16.5%
Biomass	1.3%	1.2%
Geothermal	0.4%	0.4%
Solar	4.0%	4.7%
Wind	9.1%	10.1%
Other fuels	0.9%	0.9%
Total	100%	100%

r = revised

Note: Other fuels include: Pumped hydro, other gases, and diesel/fuel oil. Totals may not equal 100% due to rounding.

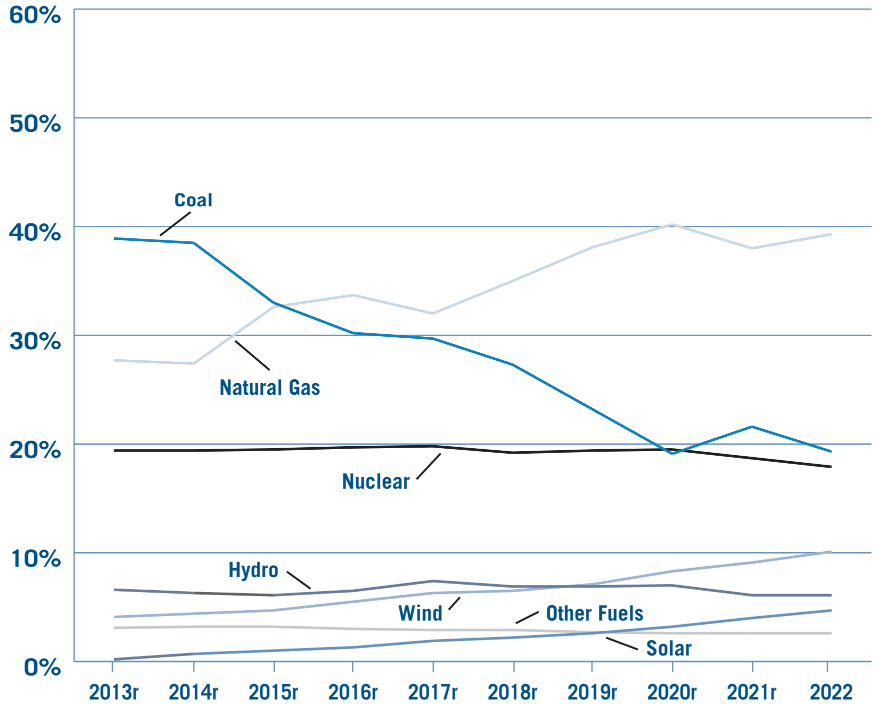
U.S. Electric Utility: Owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. This includes investor-owned utilities, public power, and cooperatives.

Non-Utility Power Producer: Non-utility power producers include qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) without a designated franchised service area.

Source: U.S. Department of Energy, Energy Information Administration (EIA), EEI Energy Supply and Finance Department, April 2023

Fuel Sources for Net Electric Generation (Percent of Total Electric Generation) 2013-2022

U.S. ELECTRIC UTILITY AND NON-UTILITY



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Source: Energy Information Administration (EIA), U.S. Department of Energy; EEI Energy Supply and Finance Department, April 2023

two states saw residential electricity sales rise in 2022. Hawaii (-2.7%) and Michigan (-2.2%) had the largest percentage declines in residential electricity sales.

The variations in year-to-year residential sales trends across states may be due, in part, to the impact of differing protocols and mandates in the aftermath of COVID-19. States with residential electricity sales growth may have seen a continued increase in 2022 in the number of people working from home. Conversely, relatively fewer people may have worked from home in states with residential sales declines in 2022.

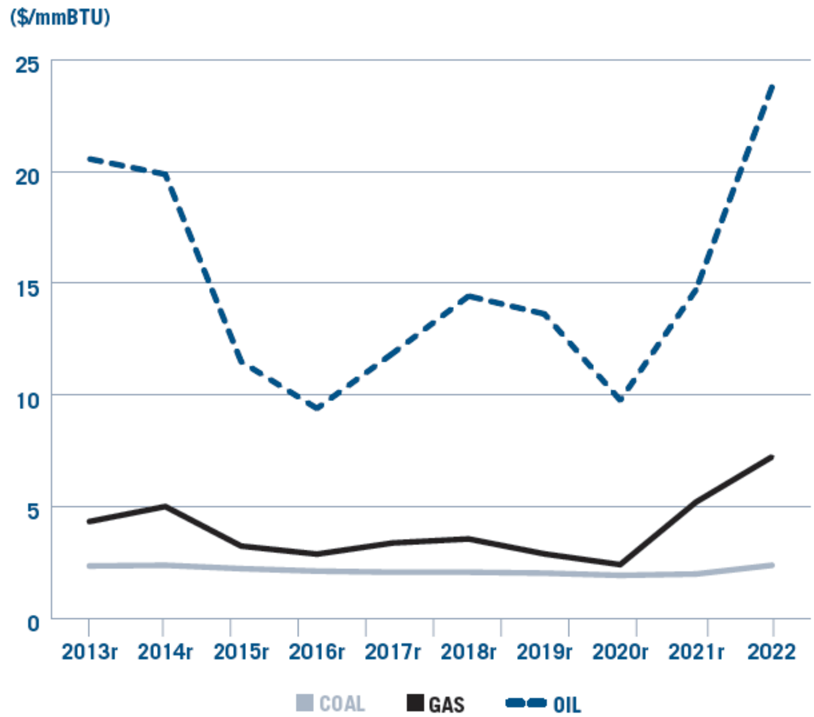
Coal

Generation from coal-fired plants in 2022 was 7.7% below the 2021 total. Coal accounted for 19.3% of total electricity generation nationwide in 2022. Coal's 828,993 GWh of generation placed it second, behind natural gas, among the fuels that contributed to total nationwide generation. The coal fleet's capacity factor decreased from 49% in 2021 to 48% in 2022.

The average cost to produce electricity from coal increased 12.3%, from \$33.04/MWh in 2021 to \$37.11/MWh in 2022. A 19.7% increase in the average price of coal, from \$1.98 per million British

Average Cost of Fossil Fuels 2013–2022

U.S. ELECTRIC UTILITY AND NON-UTILITY



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Source: Energy Information Administration (EIA), U.S. Department of Energy; EEI Energy Supply and Finance Department, April 2023

Thermal Units (MMBtu) in 2021 to $2.37 MMBtu in 2022, drove up the fuel cost component of coal generation. This increase was offset by a 6.3% decline in average operations and maintenance expenses, which dropped from $10.3/MWh in 2021 to $9.65/MWh in 2022. Because sharply higher natural gas fuel prices have made natural gas generation far more costly than coal, the more muted increase in coal generation costs preserved coal's place as the second-most expensive fuel for electricity generation in 2022 as it was in 2021.

Annual coal generation returned to its previous declining trend after a brief increase in 2021, mainly because of constrained coal supply.

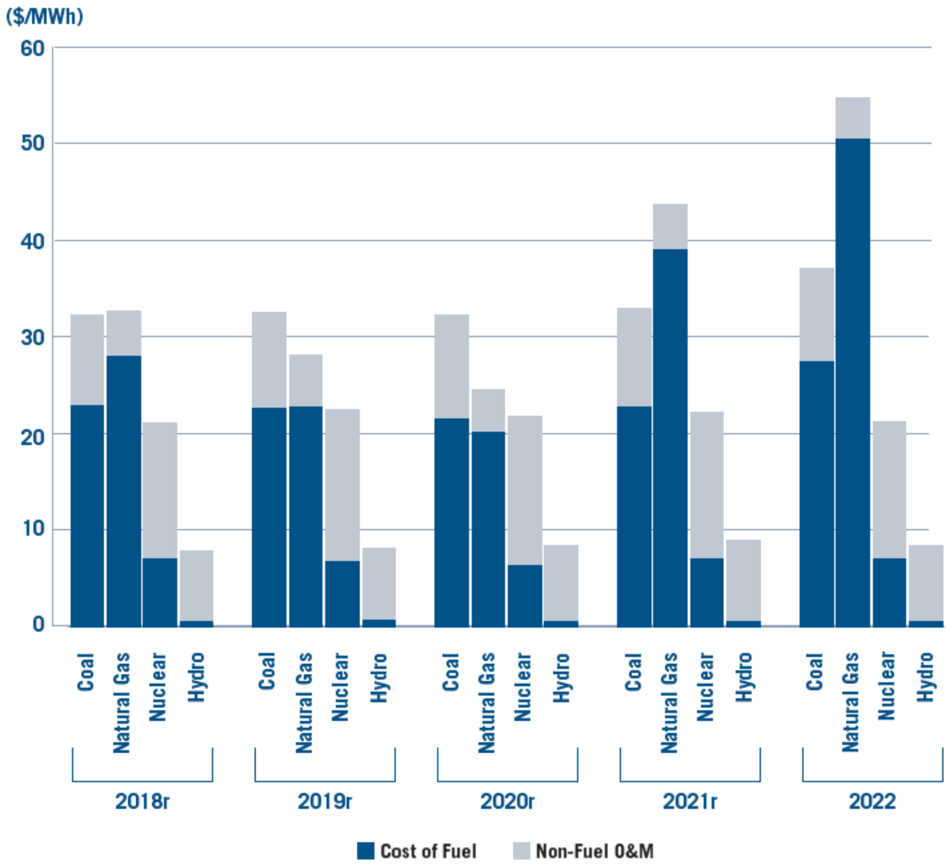
The decline in coal generation in 2022 was accompanied by a decrease in coal plants' average capacity factor along with a significant increase in coal capacity retirements compared to 2021. From 2018 through 2022, only 103 MW of new coal capacity came online compared to 59,437 MW of coal retirements. Another 42,365 MW of coal capacity is projected to retire from 2023 through 2027.

Natural Gas

Natural gas powered 39.3% of 2022's total generation—more than

Average Cost to Produce Electricity 2018–2022

U.S. ELECTRIC UTILITY AND NON-UTILITY



r = revised

Note: 2022 results are preliminary. Totals may reflect rounding.

U.S. Electric Utility: Owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. This includes investor-owned utilities, public power, and cooperatives.

Non-Utility Power Producer: Non-utility power producers include qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) without a designated franchised service area.

Source: The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2023

any other single fuel type. That share increased more than one percentage point from its 2021 level, but it remains below the 40.2% of 2020. The average cost of natural gas for electricity generation rose dramatically, increasing 38.8%, from $5.20/MMBtu in 2021 to $7.22/MMBtu, in 2022, its highest level in recent history. As a result, the average cost to produce electricity from natural gas rose 25.3% in 2022 versus 2021 and was 47.6% higher than the average cost to produce electricity from coal.

Renewables

The electric industry continues to add record amounts of renewable capacity. As a result, electric generation from carbon-free sources increased to 1,742,920 MWh in 2022, representing 40.5% of the electric power industry's total generation. Generation from all renewable sources was 971,383 MWh, or 22.6% of the total in 2022 compared with 864,432 MWh, or 20.8%, in 2021.

Conventional hydroelectric generation rose to 261,999 MWh, a 4.1% increase from 2021's 251,585 MWh. It accounted for 6.1% of electricity generation in 2022, the same as last year but down from 7.0% in 2020. Generation from wind power increased 15%, from 378,197 MWh in 2021 to 434,812 MWh in 2022 and accounted for 10.1% of 2022's total electricity generation. Solar generation increased 24.1%, from 164,423 MWh in 2021 to 204,111 MWh in 2022, reaching 4.7% of total electricity generation. Utility-scale solar accounted for 145,599 MWh, or 71.3%, of solar generation, an increase from 70.1% in 2021.

Nuclear

Nuclear generation decreased 0.8% in 2022 and accounted for 17.9% of total electric power generation, down from 18.7% in 2021. The decline was due to reduced capacity resulting from nuclear plant retirements; 6,120 MW of nuclear capacity was retired from 2018 through 2022, with the retirement of 823 MW at the Palisades power plants in Michigan in 2022 the most recent. Another 2,323 MW is projected to be retired over the next five years through closure of the Diablo Canyon power plant in California. Nuclear power plants had an average capacity factor of 92.6% in 2022 compared to average capacity factors of 47.8% for coal and 36.7% for natural gas.

Nuclear fuel costs increased 0.7%, from $6.99/MWh in 2021 to $7.04/MWh in 2022. However, non-fuel operations and maintenance costs decreased 7.1%, from $15.26/MWh in 2021 to $14.18/MWh in 2022. As a result, the total cost to produce electricity from nuclear power declined 4.7%.

A total of 3,953 MW of nuclear capacity is expected to come online from 2023 through 2027. Two existing plants have planned expansions — 2,200 MW at Vogtle (GA) and 1,213 MW at Bellefonte (AL). At the same time, small modular nuclear reactors (SMRs) will begin to contribute to nuclear capacity increases with 540 MW from the NuScale Small Nuclear Modular Project (ID) expected to come online in 2024. Looking farther into the future, the Tennessee Valley Authority announced an agreement with GE-Hitachi to support the potential deployment of a BWRX-300 SMR at its Clinch River site. In addition, X-energy announced the construction of a TRISO-X Fuel Fabrication Facility (FT3), North America's first commercial-scale facility dedicated to fueling High-Assay Low-Enriched Uranium (HALEU)-based reactors, that is expected to be operational by 2025.

Industry Financial Performance

Income Statement

- Energy Operating Revenues rose 15.8% versus last year. The strong gain was mostly a result of higher fuel commodity prices, which are mostly passed through under rate regulation and do not increase utility profits. Nationwide electricity generation increased 2.7% as residential and commercial sales each gained more than 3% year-to-year. Industrial sales were flat after rising more than 4% in 2021. Driven higher by fuel costs, the average retail price of electricity nationwide increased 12.5%, according to EIA data. By contrast, the average retail price nationwide rose only 7.7% over the entire 2010 through 2020 10-year period. Almost all 44 utilities included in EEI's industry consolidated data reported higher revenue in 2022.

- Inflation pressures drove generation costs sharply higher for the second straight year. The cost of natural gas for electric generation jumped more than 30% while the cost of coal rose about 20%, based on EIA data. As a result, the industry's consolidated Total Electric Generation Cost climbed 29.2% year-to-year while Gas Cost increased 54.3%. These two line items combined to drive the industry's Total Energy Operating Expenses up 33.3%. Slightly less than half the utilities tracked by EEI separately disclose Electric Fuel Expense and Cost of Purchased Power. Based on that data, the industry's aggregate reported Electric Fuel Expense rose 56.5% while Cost of Purchased Power increased 31.1%.

- Operations and Maintenance (O&M) costs rose 7.9% after gaining only 1.0% to 1.5% annually from 2018 through 2020. Utilities' O&M spending is benefitting from smart-grid investment productivity and the industry worked hard to constrain O&M expenses during the pandemic to address revenue declines. Yet O&M costs are also driven by essential reliability needs. Most utilities showed a year-to-year increase in O&M costs for 2022.

- Depreciation & Amortization (D&A) expenses rose 7.5%. This metric increased for 39 of the 44 constituent companies, reflecting the industry's ongoing widespread and diverse investments in new clean generation, transmission, distribution and grid modernization.

- Most of the $4.9 billion, or 23.5%, year-to-year jump in Other Operating Expenses reflects accounting for non-utility costs at one large company. Only six other utilities made small contributions to the industry total. None of these reflect meaningful industry-wide trends.

- Operating Income rose $5.0 billion, or 7.2%, versus 2021. Higher Energy Operating Revenues were offset by sharply higher generation and gas costs while Operations and Maintenance expenses and Depreciation and Amortization expenses also increased. Operating Income rose for 28 companies and declined for 16.

- Total Other Recurring Revenue declined $4.1 billion, or 33.9%, due almost entirely to a $4.3 billion decline in Other Revenue. This in turn was driven mostly by a $3.75 billion decline at just one of the 44 underlying utilities and does not reflect a broad industry trend.

- Total Non-Recurring Revenue was slightly positive after 2021's small deficit, but only a few utilities contributed to the 2022 total. 2021's deficit resulted primarily from the sale of impaired fossil generation assets at one utility. Activity in each year was insignificant in terms of broad industry trends.
- Interest Expense rose by 3.4%, reflecting in part the rise in both short- and long-term interest rates during 2022. However, this line item increased for 35 of the 44 underlying companies and rose markedly for some utilities.
- Net Income Before Taxes increased 6.4%, while Net Income rose 3.1%. These figures are driven by the industry's largest companies and mask a wide variation in company-specific results. Pre-Tax Income rose at 24 companies and declined at 20. Net Income rose at 20 and fell at 24. The year-to-year change in both metrics showed considerable variation across companies.
- The industry's aggregate Common Dividend payments rose 3.1% versus 2021, although the average percentage dividend increase was 5.2%. Nearly all utilities raised their dividend in 2022. The industry's reliable stock dividends continue to offer a welcome source of income for savings-oriented investors.

Consolidated Income Statement

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

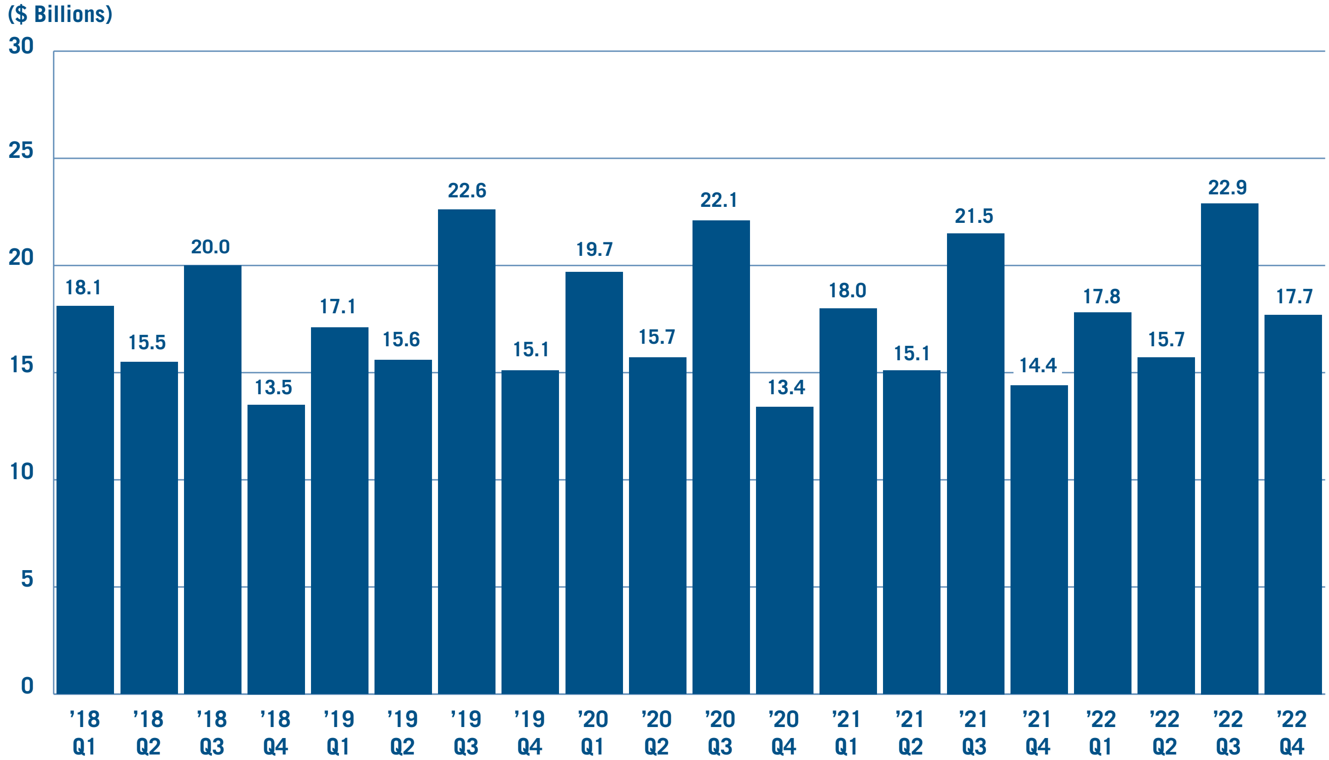
($ Millions)	12 Months Ended 12/31/2022	12/31/2021r	% Change
Energy Operating Revenues	$424,428	$366,615	15.8%
Energy Operating Expenses			
Total Electrical Generation Cost	112,572	87,125	29.2%
Gas Cost	26,083	16,910	54.3%
Total Energy Operating Expenses	**138,655**	**104,035**	**33.3%**
Revenues less energy operating expenses	**285,773**	**262,580**	**8.8%**
Other Operating Expenses			
Operations & maintenance	101,242	93,854	7.9%
Depreciation & Amortization	61,458	57,193	7.5%
Taxes (not income) - Total	23,304	21,647	7.7%
Other Operating Expenses	25,746	20,846	23.5%
Total Operating Expenses	**350,405**	**297,574**	**17.8%**
Operating Income	**74,023**	**69,041**	**7.2%**
Other Recurring Revenue			
Partnership Income	2,588	2,621	(1.3%)
Allowance for Equity Funds Used for Construction	2,274	2,085	9.1%
Other Revenue	3,191	7,476	(57.3%)
Total Other Recurring Revenue	**8,052**	**12,182**	**(33.9%)**
Non-Recurring Revenue			
Gain on Sale of Assets	510	(1,902)	(126.8%)
Other Non-Recurring Revenue	341	471	(27.6%)
Total Non-Recurring Revenue	**(851**	**(1,430)**	**(159.5%)**
Interest expense	26,987	26,112	3.4%
Other expenses	822	385	113.3%
Asset Writedowns	2,985	1,199	148.9%
Other Non-Recurring Expenses	4,366	7,221	(39.5%)
Total Non-Recurring Expenses	7,351	8,421	(12.7%)
Net Income Before Taxes	**47,766**	**44,874**	**6.4%**
Provision for Taxes	3,045	3,390	(10.2%)
Dividends on Preferred Stock of Subsidiary	-	-	NM
Other Minority Interest Expense	-	-	NM
Minority Interest Expense	-	-	NM
Trust Preferred Security Payments	-	-	NM
Other After-tax Items	-	-	NM
Total Minority Interest and Other After-tax Items	-	-	NM
Net Income Before Extraordinary Items	**44,721**	**41,485**	**7.8%**
Discontinued Operations	(1,151)	793	(245.2%)
Change in Accounting Principles	-	-	NM
Early Retirement of Debt	-	-	NM
Other Extraordinary Items	-	-	NM
Total Extraordinary Items	(1,151)	793	(245.2%)
Net Income	**43,570**	**42,277**	**3.1%**
Preferred Dividends Declared	508	573	(11.3%)
Other Preferred Dividends after Net Income	2	2	0.0%
Other Changes to Net Income	(4)	(2)	100.0%
Net Income Attributable to Noncontrolling Interests	(513)	(527)	NA
Net Income Available to Common	**43,569**	**42,227**	**3.2%**
Common Dividends	**31,016**	**30,075**	**3.1%**

r = revised NM = not meaningful

Source: S&P Global Market Intelligence and EEI Finance Department.

Quarterly Net Operating Income

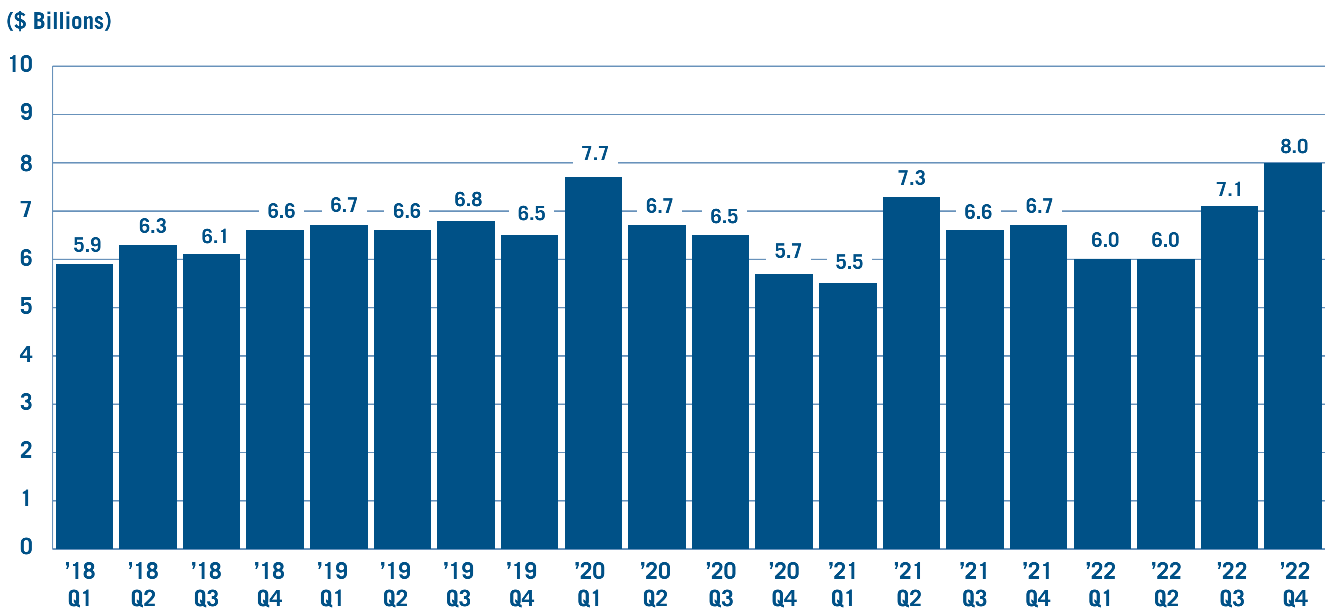
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence and EEI Finance Department.

Quarterly Interest Expense

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence and EEI Finance Department.

Individual Non-Recurring and Extraordinary Items 2013–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2013	2014	2015	2016	2017	2018	2019	2020	2021r	2022
Net Gain (Loss) on Sale of Assets	414	996	789	767	1,012	5,272	3,049	**(398)**	(1,902)	510
Other Non-Recurring Revenue	78	296	(4)	888	493	131	117	–	471	341
Total Non-Recurring Revenue	**492**	**1,292**	**785**	**1,655**	**1,505**	**5,403**	**3,167**	**(398)**	**(1,430)**	**851**
Asset Writedowns	(4,276)	(8,762)	(5,189)	(17,487)	(4,166)	(4,121)	(3,470)	6,704	1,199	2,985
Other Non-Recurring Charges	(3,510)	(2,675)	(1,764)	(3,109)	(5,630)	(17,841)	(13,034)	8,504	7,221	4,366
Total Non-Recurring Charges	**(7,786)**	**(11,437)**	**(6,953)**	**(20,596)**	**(9,796)**	**(21,962)**	**(16,504)**	**15,208**	**8,421**	**7,351**
Discontinued Operations	(88)	295	(1,148)	(732)	(1,554)	602	1,243	17	793	(1,151)
Change in Accounting Principles	–	–	–	–	–	–	–	–	–	–
Early Retirement of Debt	–	–	–	–	–	–	–	–	–	–
Other Extraordinary Items	–	–	–	–	–	–	–	–	–	–
Total Extraordinary Items	**(88)**	**295**	**(1,148)**	**(732)**	**(1,554)**	**602**	**1,243**	**17**	**793**	**(1,151)**
Total Non-Recurring and Extraordinary Items	**(7,381)**	**(9,850)**	**(7,316)**	**(19,674)**	**(9,844)**	**(15,957)**	**(12,094)**	**(15,589)**	**(9,058)**	**(7,651)**

r = revised Note: Figures represent net industry totals. Totals may reflect rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

Top Net Non-Recurring and Extraordinary Gains (Losses) 2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

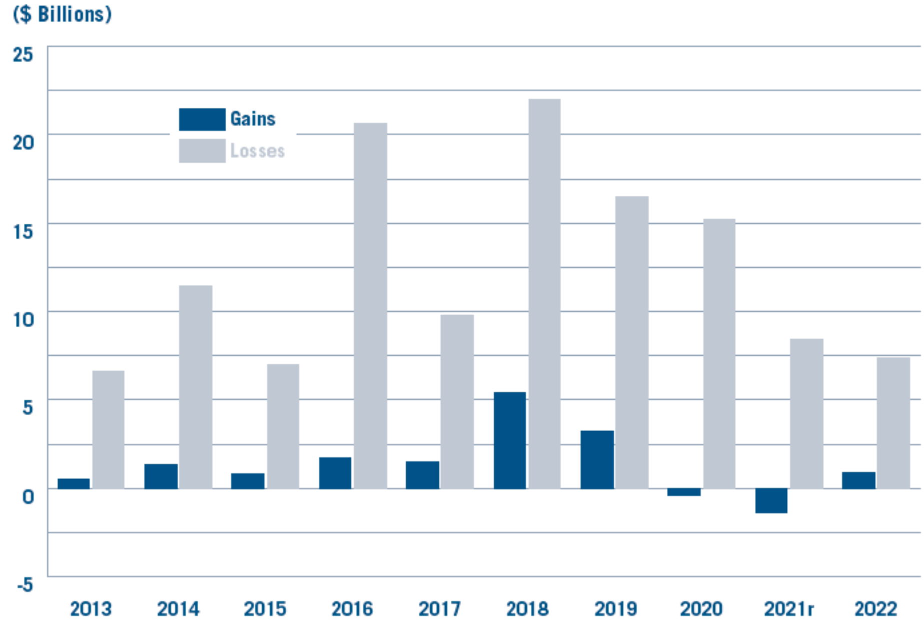
($ Millions)

Company	Gains	Losses	Net Total
Dominion Energy	(404)	2,377	2,781
Edison International	10	1,581	1,571
PG&E Corp	–	1,322	1,322
Duke Energy	22	499	477
Southern Company	57	434	377
CenterPoint Energy	303	–	303
OGE Energy	282	–	282
Sempra Energy	–	259	259
American Electric Power	(210)	49	259
FirstEnergy	–	171	171

Source: S&P Global Market Intelligence and EEI Finance Department.

Aggregate Non-Recurring and Extraordinary Items 2013–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



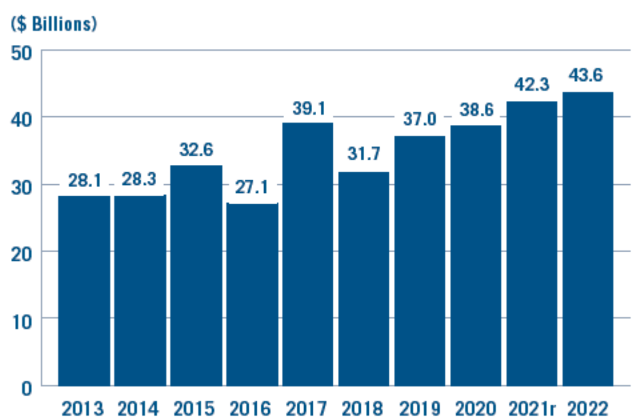
	2013	2014	2015	2016	2017	2018	2019	2020	2021r	2022	Total
Gains	0.5	1.3	0.8	1.7	1.5	5.4	3.2	(0.4)	(1.4)	0.9	13.3
Losses	6.6	11.4	7.0	20.6	9.8	22.0	16.5	15.2	8.4	7.4	124.9
Total	(6.2)	(10.1)	(6.2)	(18.9)	(8.3)	(16.6)	(13.3)	(15.6)	(9.9)	(6.5)	(111.6)

r = revised Note: Totals may reflect rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

Net Income 2013–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

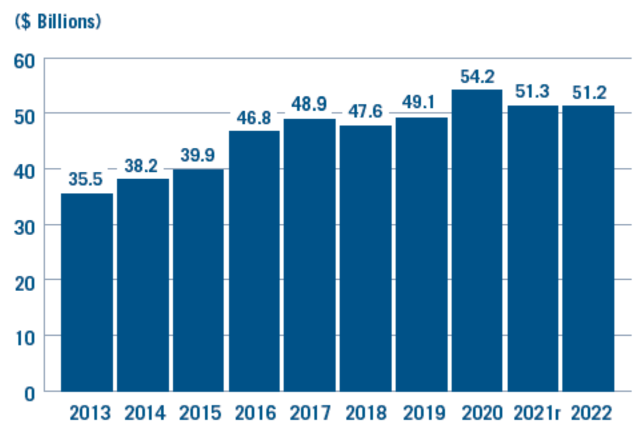


r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

Net Income Before Non-Recurring and Extraordinary Items 2013-2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

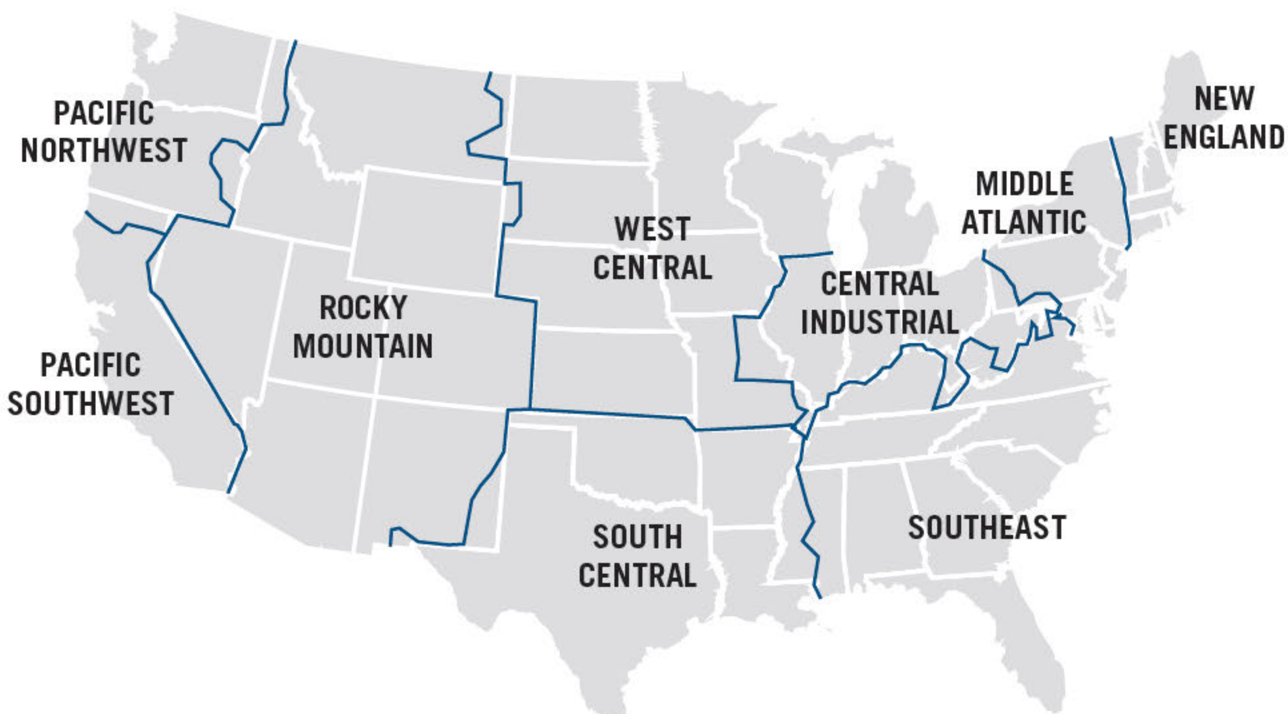
U.S. Electric Output (GWh)
Periods Ending December 31

Region	2022	2021	% Change
New England	115,781	115,930	(0.1%)
Mid-Atlantic	419,466	418,296	0.3%
Central Industrial	657,622	651,041	1.0%
West Central	341,836	335,136	2.0%
Southeast	1,036,554	1,014,838	2.1%
South Central	840,535	778,018	8.0%
Rocky Mountain	296,141	292,947	1.1%
Pacific Northwest	161,364	158,170	2.0%
Pacific Southwest	273,602	268,259	2.0%
Total United States	**4,142,901**	**4,032,635**	**2.7%**

Note: Represents all power placed on grid for distribution to end customers; does not include Alaska or Hawaii.

Source: EEI Business Analytics.

EEI U.S. Electric Output – Regions



Source: EEI Business Analytics.

U.S. Weather
January – December 2022

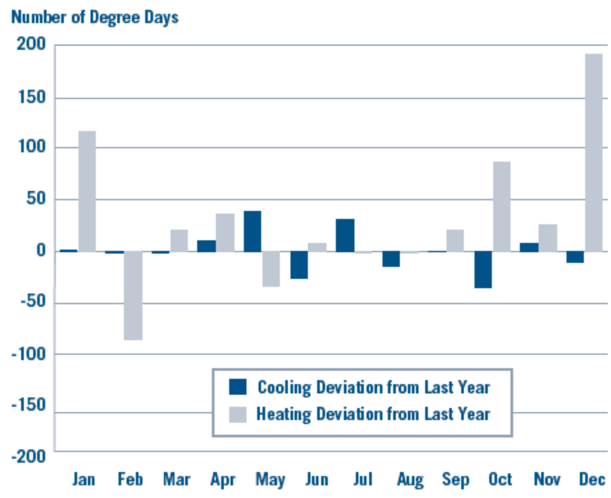
	Total	Dev from Norm	% Change	Dev from Last Year	% Change
Cooling Degree Days					
New England	651	234	56%	(4)	(1%)
Mid-Atlantic	856	200	30%	(56)	(6%)
East North Central	827	119	17%	(141)	(15%)
West North Central	1,090	162	17%	(27)	(2%)
South Atlantic	2,177	213	11%	(50)	(2%)
East South Central	1,725	177	11%	41	2%
West South Central	2,918	469	19%	270	10%
Mountain	1,384	141	11%	(19)	(1%)
Pacific	975	271	38%	69	8%
United States	**1,440**	**224**	**18%**	**0**	**0%**
Heating Degree Days					
New England	6,107	(504)	(8%)	274	5%
Mid-Atlantic	5,554	(357)	(6%)	456	9%
East North Central	6,352	(145)	(2%)	605	11%
West North Central	6,947	197	3%	895	15%
South Atlantic	2,673	(180)	(6%)	220	9%
East South Central	3,489	(115)	(3%)	334	11%
West South Central	2,366	79	3%	402	20%
Mountain	5,207	(2)	(0%)	507	11%
Pacific	3,124	(104)	(3%)	24	1%
United States	**4,392**	**(132)**	**(3%)**	**380**	**9%**

A mean daily temperature (average of the daily maximum and minimum temperatures) of 65 degrees Fahrenheit is the base for both heating and cooling degree day computations. National averages are population weighted.

Source: National Oceanic and Atmospheric Administration, National Weather Service, Climate Prediction Center.

2022 Weather Compared to 2021

AS MEASURED BY DEVIATIONS BETWEEN THE TWO YEARS



Source: National Oceanic and Atmospheric Administration and National Weather Service.

	Cooling Deviation From Last Year	Heating Deviation From Last Year
Jan	1	116
Feb	(2)	(85)
Mar	(2)	20
Apr	10	36
May	39	(34)
Jun	(26)	8
Jul	31	(2)
Aug	(14)	(2)
Sep	0	20
Oct	(35)	86
Nov	8	26
Dec	(10)	191
Total	**0**	**380**

Heating and Cooling Degree Days and Percent Changes
January—December 2022

	COOLING DEGREE DAYS			HEATING DEGREE DAYS			PERCENTAGE CHANGE			
	Total	Deviation From Norm	Deviation From Last Yr	Total	Deviation From Norm	Deviation From Last Yr	Cooling Degree Change From Norm	Cooling Degree Change From Last Yr	Heating Degree Change From Norm	Heating Degree Change From Last Yr
Jan	5	(4)	1	927	10	116	(44.4%)	25.0%	1.1%	14.3%
Feb	8	0	(2)	726	(6)	(85)	0.0%	(20.0%)	(0.8%)	(10.5%)
Mar	18	0	(2)	539	(54)	20	0.0%	(10.0%)	(9.1%)	3.9%
First Quarter	**31**	**(4)**	**(3)**	**2,192**	**(50)**	**51**	**(11.4%)**	**(8.8%)**	**(2.2%)**	**2.4%**
Apr	44	14	10	357	12	36	46.7%	29.4%	3.5%	11.2%
May	140	43	39	127	(32)	(34)	44.3%	38.6%	(20.1%)	(21.1%)
Jun	249	36	(26)	27	(12)	8	16.9%	(9.5%)	(30.8%)	42.1%
Second Quarter	**433**	**93**	**23**	**511**	**(32)**	**10**	**27.4%**	**5.6%**	**(5.9%)**	**2.0%**
Jul	373	52	31	3	(6)	(2)	16.2%	9.1%	(66.7%)	(40.0%)
Aug	340	50	(14)	4	(11)	(2)	17.2%	(4.0%)	(73.3%)	(33.3%)
Sep	190	35	0	59	(18)	20	22.6%	0.0%	(23.4%)	51.3%
Third Quarter	**903**	**137**	**17**	**66**	**(35)**	**16**	**17.9%**	**1.9%**	**(34.7%)**	**32.0%**
Oct	43	(10)	(35)	272	(10)	86	(18.9%)	(44.9%)	(3.5%)	46.2%
Nov	20	5	8	537	(2)	26	33.3%	66.7%	(0.4%)	5.1%
Dec	10	3	(10)	814	(3)	191	42.9%	(50.0%)	(0.4%)	30.7%
Fourth Quarter	**73**	**(2)**	**(37)**	**1,623**	**(15)**	**303**	**(2.7%)**	**(33.6%)**	**(0.9%)**	**23.0%**
Full Year	**1,440**	**224**	**0**	**4,392**	**(132)**	**380**	**18.4%**	**0.0%**	**(2.9%)**	**9.5%**

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Heating Degree Days Percentage Change from Historical Norm	(0.6)	1.1	(9.1)	(14.8)	(14.2)	(4.2)	(4.4)	(11.9)	(11.3)	(2.9)
Cooling Degree Days Percentage Change from Historical Norm	10.9	5.8	19.2	29.4	16.0	26.4	20.3	21.1	18.3	18.4

A mean daily temperature (average of the daily maximum and minimum temperatures) of 65°F is the base for both heating and cooling degree day computations. National averages are population weighted.

Source: National Oceanic and Atmospheric Administration and National Weather Service.

Balance Sheet

- Economic growth slowed in 2022 after 2021's strong post-pandemic rebound. Real gross domestic product (GDP) posted negative readings in 2022's first half — at -1.6% in Q1 and -0.6% in Q2 — spurring widespread debate over whether the U.S. had officially entered a recession. Growth recovered in the year's second half as real GDP gained 3.2% in Q3 and 2.6% in Q4.

- As in 2021, inflation remained well above the U.S. Federal Reserve's (Fed) 2% target. The headline CPI posted monthly readings of 7% to 8% through November and over 6% in December. While the Fed held short-term rates at zero during 2021 to support the post-Covid recovery, in 2022 it raised rates seven times to a 4.25% to 4.50% range at year-end. As a result, short-term corporate borrowing costs reached levels not seen since before the 2008/2009 financial crisis.

- Bond yields climbed steadily but remained far below levels associated with high inflation in previous inflation cycles. Bond investors continued to see inflation as a short-term effect of strained supply chains contending with the post-Covid global economic reopening. The 10-year Treasury yield entered 2022 at 1.6% and ended the year at just 3.9%. Investment-grade corporates (Moody's Baa rating) could borrow long-term for 5% to 6% throughout 2022's second half, even with inflation above 7%.

- The industry's financial condition remained strong in 2022. The multi-year trend toward increased state-regulated utility operations continued, along with leverage appropriate for a lower risk profile. The industry's balance sheet leverage, in aggregate, increased slightly. However, aggregate figures convey only broad, long-term trends and emphasize large utility holding companies. Balance sheet structures vary widely across the industry. Leverage increased more than one percentage point at 18 companies. Leverage was reduced by more than one percentage point at 14 companies and was largely unchanged at the remaining 12 companies.

- The industry's consolidated total debt rose in 2022, a natural consequence of financing the aggressive build-out of clean-energy infrastructure. For the first time in years, rising interest rates meaningfully increased borrowing costs. Nevertheless, most companies managed balance sheet ratios and cash flows to maintain investment-grade credit ratings. Long-term debt increased at 32 utilities and declined at 12. The three largest instances where debt declined were associated with strategic repositioning. Balance sheet management produced scattered smaller debt reductions. Short-term debt rose at 28 companies, decreased at 12 and was unchanged (at zero each year) at four.

- Common equity issuance remained subdued, following three active years from 2018 through 2020. Many utilities sought to fund capex without equity dilution, in some cases with proceeds from asset sales. Just seven large utilities accounted for 80% of the industry's \$11.0 billion total; four raised \$1 billion to \$2 billion during the year while three issued anywhere from \$600 million to \$1 billion. Another 17 companies issued equity in smaller amounts. Thirty utilities reported equity issuance in 2021. Issuance was strong in both 2020 and 2019 as companies augmented balance sheets and addressed the impact of tax reform. Equity issuance was also strong in 2018 as utilities took advantage of high price-earnings ratios and welcoming capital markets to fund capex and offset debt issuance.

- Property, plant and equipment in service (PPE in Service, net) rose 4.4% from year-end 2021 and 7.5% over the level at year-end 2020. This metric grew at nearly all 44 utilities which constitute EEI's consolidated data. Such broad growth indicates the size and scope of the industry's build-out of new renewable generation, new transmission, reliability-related infrastructure and other capital projects related to the nation's clean energy transition. Construction work in progress (CWIP), a component of the PPE in Service total, jumped nearly 21% over the year-end 2021 total and more than 27% from year-end 2020. CWIP accounts for capital investment in utility infrastructure still under construction and not yet in service. The accelerating

Consolidated Balance Sheet

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	12/31/2022	12/31/2021r	% Change	$ Change
PP&E in service, gross	1,803,608	1,709,378	5.5%	94,230
Accumulated depreciation	517,398	488,289	6.0%	29,109
PP&E in service, net	1,286,210	1,221,089	5.3%	65,121
Construction work in progress	103,931	85,777	21.2%	18,154
Net nuclear fuel	12,933	12,957	(0.2%)	(24)
Other property	15,315	15,873	(3.5%)	(558)
PP&E, net	1,418,389	1,335,697	6.2%	82,692
Cash & cash equivalents	13,378	17,330	(22.8%)	(3,952)
Accounts receivable	56,653	46,241	22.5%	10,412
Inventories	29,569	23,844	24.0%	5,725
Other current assets	81,301	70,443	15.4%	10,859
Total current assets	180,901	157,857	14.6%	23,044
Total investments	109,004	120,117	(9.3%)	(11,114)
Other assets	310,526	326,970	(5.0%)	(16,444)
Total Assets	**2,018,819**	**1,940,641**	**4.0%**	**78,179**
Common equity	539,825	526,137	2.6%	13,688
Preferred equity	10,071	10,870	(7.4%)	(799)
Noncontrolling interests	28,036	25,939	8.1%	2,097
Total equity	577,931	562,945	2.7%	14,986
Short-term debt	49,672	39,754	24.9%	9,917
Current portion of long-term debt	50,729	36,085	40.6%	14,643
Short-term and current long-term debt	100,400	75,840	32.4%	24,561
Accounts payable	91,703	77,408	18.5%	14,294
Other current liabilities	60,594	60,348	0.4%	246
Current liabilities	252,697	213,596	18.3%	39,100
Deferred taxes	113,287	109,099	3.8%	4,188
Non-current portion of long-term debt	740,215	694,027	6.7%	46,188
Other liabilities	333,109	358,360	(7.0%)	(25,251)
Total liabilities	1,439,308	1,375,082	4.7%	64,226
Subsidiary preferred	421	712	(40.9%)	(291)
Other mezzanine	1,159	1,901	(39.0%)	(742)
Total mezzanine level	1,580	2,613	(39.5%)	(1,033)
Total Liabilities and Owner's Equity	**2,018,819**	**1,940,641**	**4.0%**	**78,179**

r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

Capitalization Structure

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Capitalization Structure ($M)	12/31/2022	12/31/2021r	12/31/2020
Common Equity	539,825	526,137	494,872
Noncontrolling Interests & Preferred Equity	38,106	36,808	42,068
Long-term Debt (current & non-current)*	790,944	730,112	695,361
Total	**1,368,875**	**1,293,058**	**1,232,301**
Common Equity %	39.4%	40.7%	40.2%
Noncontrolling Interests & Preferred Equity %	2.8%	2.8%	3.4%
Long-Term Debt (current & non-current)* %	57.8%	56.5%	56.8%
Total	**100.0%**	**100.0%**	**100.0%**

r = revised
Long-term debt not adjusted for (i.e., includes) securitization bonds.
Source: S&P Global Market Intelligence and EEI Finance Department.

growth in CWIP offers another view of the industry's rising clean energy capex.

- The debt-to-capitalization ratio by category data shows the dominance of state-regulated operations in the industry. Companies in EEI's "Regulated" group represent 36 of the 44 parent level companies tracked by EEI. The remaining eight constitute the "Mostly Regulated" group.

- The tendency toward slightly higher balance sheet leverage at the consolidated industry level is not evident across individual company moves. In fact, 13 of the 36 "Regulated" companies reduced leverage in 2022 while 14 increased leverage and 9 showed no meaningful change. Leverage increased at four of the eight "Mostly Regulated" companies, declined at one and was unchanged at three.

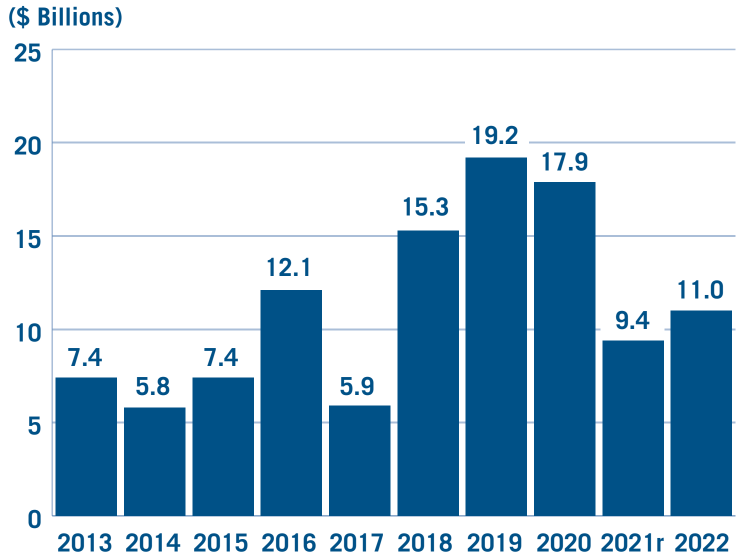
- The 3.5 percentage point jump in long-term debt as a percent of total capitalization in the Mostly Regulated group was driven largely by Exelon's separation of its regulated and competitive businesses in 2022 and the large resulting increase in leverage at the restructured Exelon.

- The dispersion across companies in both categories — with some showing higher, some lower and others no change in leverage — indicates why individual company strategies are as meaningful as consolidated totals when assessing industry trends.

- Regulated companies as a group continued to report higher balance sheet leverage than their Mostly Regulated peers. This is to be expected given their lower business risk profile.

Proceeds from Issuance of Common Equity 2013–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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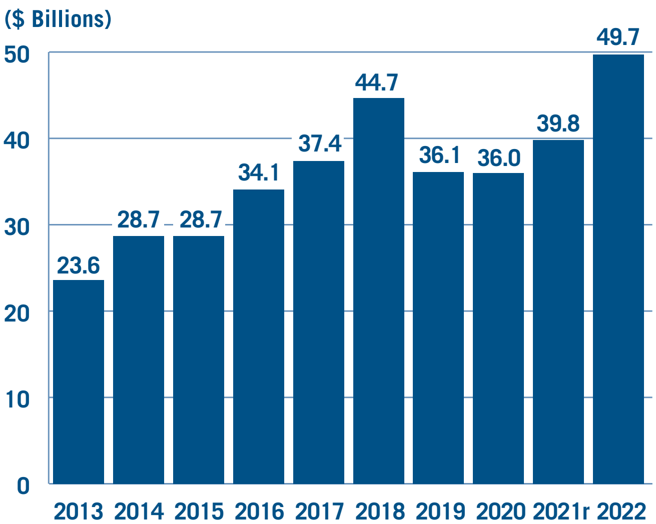
Source: S&P Global Market Intelligence and EEI Finance Department.

Short-term Debt 2013–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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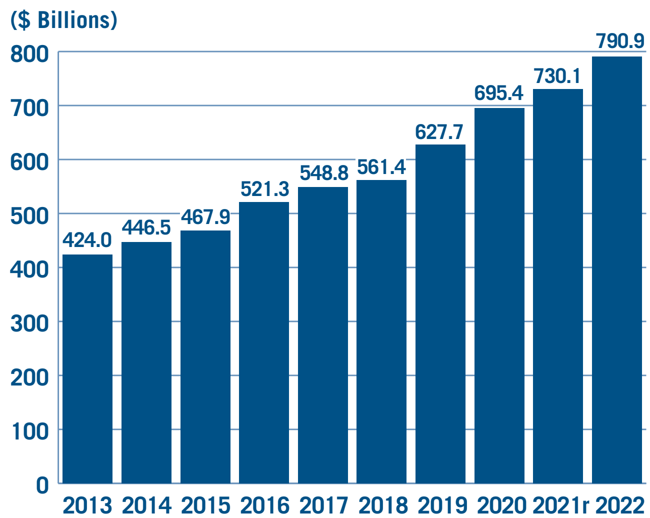
Source: S&P Global Market Intelligence and EEI Finance Department.

Long-term Debt 2013–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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Source: S&P Global Market Intelligence and EEI Finance Department.

Debt-to-Cap Ratio by Category 2022 vs. 2021r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Regulated		Mostly Regulated		Total Industry	
	Number	%	Number	%	Number	%
Lower	13	36.1%	1	12.5%	14	31.8%
No Change*	9	25.0%	3	37.5%	12	27.3%
Higher	14	38.9%	4	50.0%	18	40.9%
Total	**36**	**100.0%**	**8**	**100.0%**	**44**	**100.0%**

*No change defined as less than 1.0%

Note: December 31, 2022 vs. December 31, 2021. Refer to page v for category descriptions.

Source: S&P Global Market Intelligence and EEI Finance Department.

Capitalization Structure by Category 2022 vs. 2021r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Regulated			Mostly Regulated		
	2022	2021r	Change	2022	2021r	Change
Common Equity ($M)	388,279	367,806	20,473	151,546	158,331	(6,786)
Total Preferred Equity	22,734	21,221	1,513	15,372	15,587	(215)
Long-term Debt (current & non-current)*	603,220	560,191	43,028	187,724	169,921	17,803
Total Capitalization	1,014,233	949,218	65,015	354,642	343,839	10,803
Common Equity %	38.3%	38.7%	-0.5%	42.7%	46.0%	-3.3%
Preferred Equity %	2.2%	2.2%	0.0%	4.3%	4.5%	-0.2%
Long-Term Debt %	59.5%	59.0%	0.5%	52.9%	49.4%	3.5%
Total	**100.0%**	**100.0%**	—	**100.0%**	**100.0%**	—

r = revised

Refer to page v for category descriptions.

Note: Long-term debt not adjusted for (i.e., includes) securitization bonds.

Source: S&P Global Market Intelligence and EEI Finance Department.

PP&E In Service, Net 2018-2022

Date	PP&E in Service, Net ($M)	% Change from 12/31/2018
12/31/2022	1,286,210	21.6%
12/31/2021r	1,221,089	15.4%
12/31/2020	1,196,315	13.1%
12/31/2019	1,129,880	6.8%
12/31/2018	1,058,164	

Source: S&P Global Market Intelligence and EEI Finance Department.

Cash Flow Statement

- Net Cash Provided by Operating Activities increased by $9.9 billion, or 12.0%. Cash provided by Depreciation and Amortization (D&A), a non-cash charge on the income statement, declined by $793 million, or 1.2%, at the consolidated industry level. However, D&A increased at 37 of the 44 utility holding companies that comprise EEI's data set; widespread increases are to be expected given the industry's aggressive clean energy infrastructure buildout. The decline at the consolidated level resulted from accounting at Exelon — the industry's fifth largest utility holding company at year-end 2021 in terms of net property, plant, and equipment in service — for the separation in 2022 of its regulated and competitive operations.

- Cash provided by Deferred Taxes & Investment Credits has leveled off over the last five years compared to much higher amounts previously. Deferred taxes had been at historically high levels due to elevated capex and use of bonus depreciation. The Tax Cuts & Jobs Act (TCJA), passed in late 2017, significantly reduced deferred taxes due to the reduction in the corporate income tax rate from 35% to 21% and the elimination of bonus depreciation.

- Change in Working Capital utilized $5.1 billion more cash in 2022 than in 2021. The difference traced mostly to accounting at one large utility holding company along with smaller contributions from just a few other large utilities. Conversely, Other Operating Changes in Cash used $17.3 billion less cash in 2022 than in 2021; in both years, this activity sourced to corporate actions at just a few large utilities. Neither of these two line items reflects broad-based fundamental industry trends.

- Net Cash Used in Investing Activities increased by $33.6 billion, or 29.0%. The industry's capital spending — by far the largest component of this metric — totaled $147.7 billion in 2022, up $13.7 billion, or 10.2%, from the 2021 total. Industry capex has reached a new record high in each of the past ten years. EEI member companies continue to invest in clean energy resources and the infrastructure necessary to make the power grid more modernized, more resilient, and more secure for all customers. Spending on transmission and distribution continues to increase relative to recent years, as EEI member companies expand their focus on adaptation, hardening, and resilience (AHR) initiatives. Investment in generation continues to be driven by the development of renewable energy and natural gas generation.

- Cash provided by Asset Sales decreased $11.9 billion, or 33.8%, from $35.3 billion in 2021 to $23.4 billion in 2022. The decrease resulted in part from PPL's June 2021 sale of its U.K. utility business, Western Power Distribution (WPD), to National Grid for $10.4 billion (nearly one-third of 2021's consolidated industry total). However, 2022 was not inactive; eight utility holding companies reported asset sales in 2022 in excess of $1 billion and 25 recorded proceeds from asset sales. Cash used for Asset Purchases increased by $2.1 billion, or 12.2%, to $19.7 billion; this was driven by actions at just a few utilities, including PPL's purchase in 2022 of Rhode Island utility Narragansett Electric.

- Net Cash Provided by Financing Activities rose by $20.6 billion, or 59.8%. The large increase resulted primarily from widespread debt issuance to fund aggressive clean energy infrastructure investment programs. Debt issuance is routine in the normal course of financing operations for such a capital-intensive industry. Nearly all of the 44 underlying utility holding companies contributed to the $67.3 billion net increase in the industry's consolidated long-term debt in 2022. The Net Change in Short-term Debt also added to the cash provided by financing activities, but at a relatively lower $8.2 billion amount, up $3.2 billion from the 2021 total. Common equity issuance and share repurchases were close to last year's level in absolute terms and remained below the totals in 2018, 2019 and 2020. No utilities issued preferred equity in 2022, compared to $3.8 billion in 2021. This was the first year without preferred equity issuance since 2010.

- Dividends Paid to Common Shareholders rose 3.7%, to $31.4 billion.

Statement of Cash Flows

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

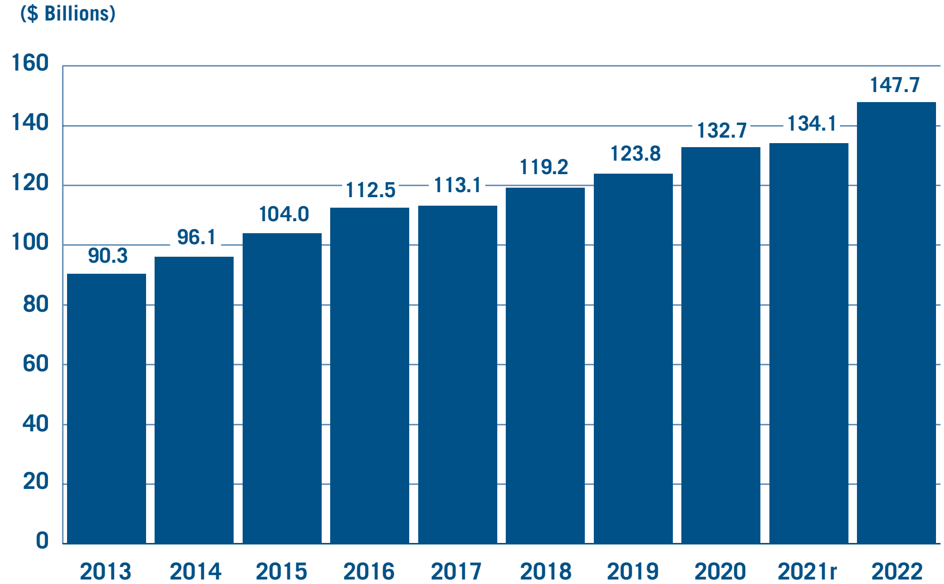
$ Millions	12 Months Ended		
	12/31/2022	12/31/2021r	% Change
Net Income	$43,570	$42,277	3.1%
Depreciation and Amortization	63,274	64,067	(1.2%)
Deferred Taxes and Investment Credits	2,659	5,278	(49.6%)
Operating Changes in AFUDC	(1,599)	(1,453)	10.1%
Change in Working Capital	(12,490)	(7,381)	69.2%
Other Operating Changes in Cash	(3,093)	(20,388)	(84.8%)
Net Cash Provided by Operating Activities	**92,322**	**82,400**	**12.0%**
Capital Expenditures	(147,748)	(134,063)	10.2%
Asset Sales	23,393	35,340	(33.8%)
Asset Purchases	(19,679)	(17,535)	12.2%
Net Non-Operating Asset Sales and Purchases	3,714	17,805	(79.1%)
Change in Nuclear Decommissioning Trust	(698)	(314)	122.2%
Investing Changes in AFUDC	45	49	(9.3%)
Other Investing Changes in Cash	(4,761)	641	NM
Net Cash Used in Investing Activities	**(149,448)**	**(115,881)**	**29.0%**
Net Change in Short-term Debt	8,221	5,043	63.0%
Net Change in Long-term Debt	67,265	45,444	48.0%
Proceeds from Issuance of Preferred Equity	–	3,783	NM
Preferred Share Repurchases	(1,158)	(2,100)	(44.9%)
Net Change in Prefered Issues	(1,158)	1,683	NM
Proceeds from Issuance of Common Equity	10,957	9,432	16.2%
Common Share Repurchases	(2,036)	(1,531)	33.0%
Net Change in Common Issues	8,921	7,901	12.9%
Dividends Paid to Common Shareholders	(31,409)	(30,279)	3.7%
Dividends Paid to Preferred Shareholders	(337)	(475)	(29.0%)
Other Dividends	–	–	NM
Dividends Paid to Shareholders	(31,746)	(30,754)	3.2%
Other Financing Changes in Cash	3,515	5,112	(31.3%)
Net Cash (Used in) Provided by Financing Activities	**55,016**	**34,430**	**59.8%**
Other Changes in Cash	(38)	12	NM
Net increase (decrease) in cash and cash equivalents	$(2,148)	$961	NM
Cash and cash equivalents at beginning of period	$15,526	$16,369	(5.2%)
Cash and cash equivalents at end of period	$13,378	$17,330	(22.8%)

r = revised NM = not meaningful

Source: S&P Global Market Intelligence and EEI Finance Department.

Capital Expenditures 2013–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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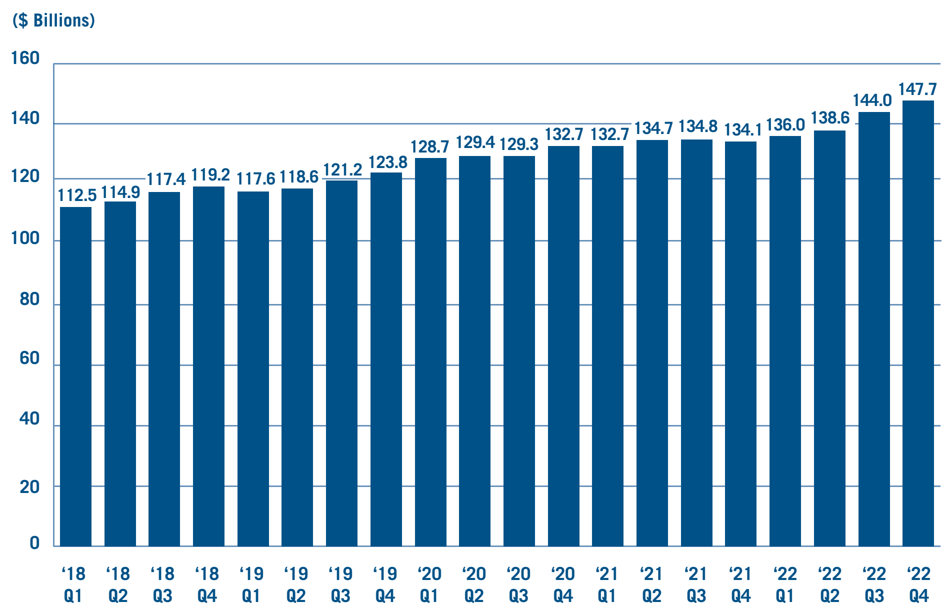
Source: S&P Global Market Intelligence, company reports, and EEI Finance Department.

Capital Expenditures—Trailing 12 Months

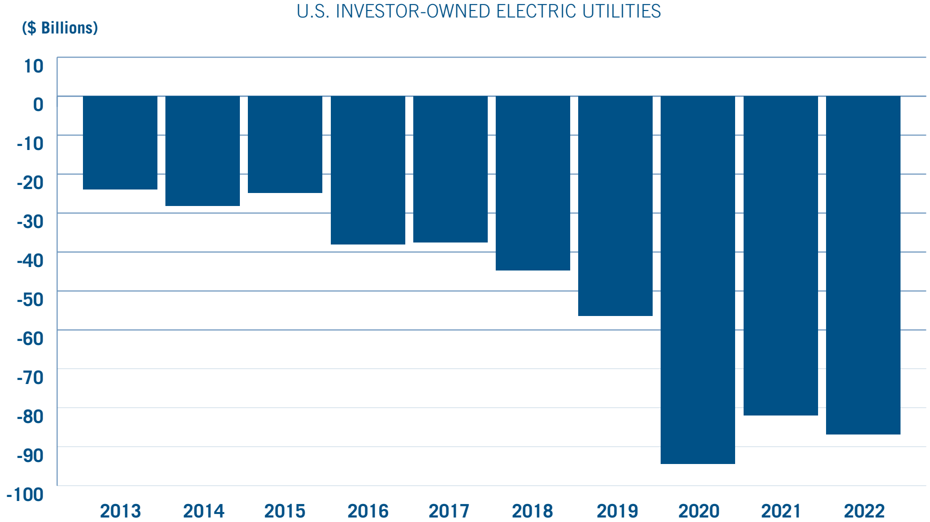
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence and EEI Finance Department.

Free Cash Flow (FCF) 2013–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



($ Billions)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Net Cash Provided by Operating Activities	87.1	89.0	101.6	98.3	101.2	100.1	95.3	67.7	82.4	92.3
Capital Expenditures	(90.3)	(96.1)	(104.0)	(112.5)	(113.1)	(119.2)	(123.8)	(132.7)	(134.1)	(147.7)
Dividends Paid to Common Shareholders	(20.8)	(21.1)	(22.5)	(23.8)	(25.5)	(25.6)	(27.9)	(29.3)	(30.3)	(31.4)
Free Cash Flow	**(24.0)**	**(28.2)**	**(24.8)**	**(38.1)**	**(37.5)**	**(44.7)**	**(56.4)**	**(94.4)**	**(81.9)**	**(86.8)**

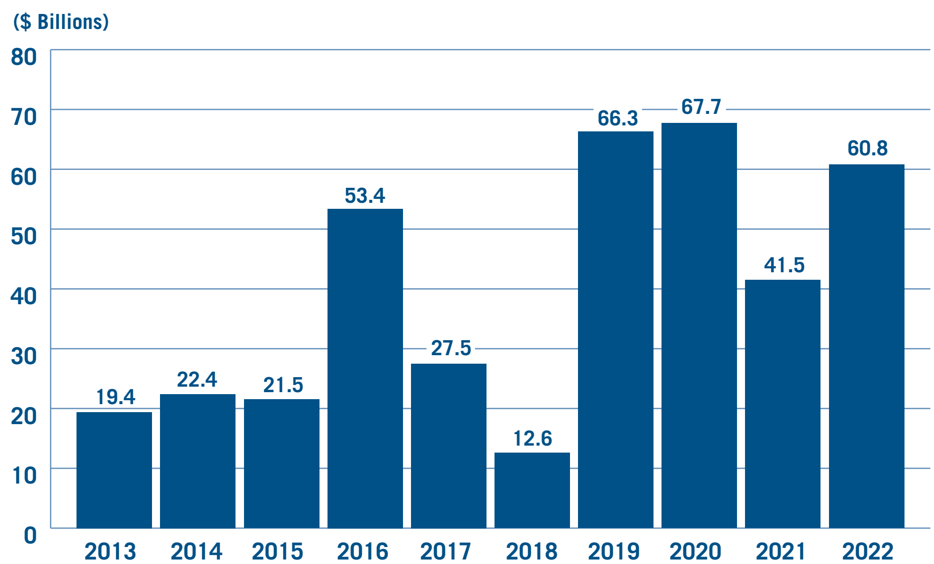
r = revised

Note: Totals may not equal sum of components due to rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

Net Change in Long-term Debt 2013–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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Note: Based on data from industry's consolidated balance sheet.

Source: S&P Global Market Intelligence and EEI Finance Department.

Rate Review Summary

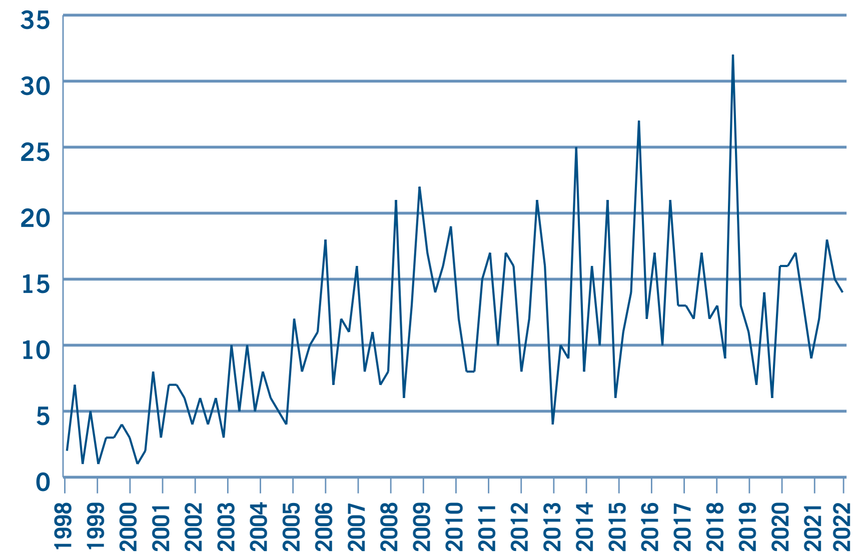
- There were 59 rate reviews filed, with 81 rate reviews decided. This is slightly more than the 55 rate reviews filed and less than the 82 rate reviews decided in 2021.
- Of the decided filings, electric companies requested revenue increases of approximately $6 billion in 2022; with approximately $4 billion approved.
- The average awarded ROE was 9.47 percent, a slight rebound from 2021 of 9.40 percent. For comparison, the average awarded ROE for 2020 was 9.43 percent, and for 2019 was 9.64 percent.
- Regulatory lag hovered around 8.01 months, which is an improvement from 8.41 months in 2021 and 8.93 months in 2020.

Key Highlights from 2022

- **Alternative Regulation** – There are many flavors of alternative regulation, but multiyear rate plans (MYRPs) were a common request in 2022. Some of these requests were the result of legislation–the most recent being Washington, which requires electric companies to request approval of MYRPs of two to four years in length, while other proposals were made to temper rising costs. However, Commissions seem amenable to MYRPs and authorized their use in a handful of decisions throughout the country.

Number of Rate Reviews Filed 1998–2022

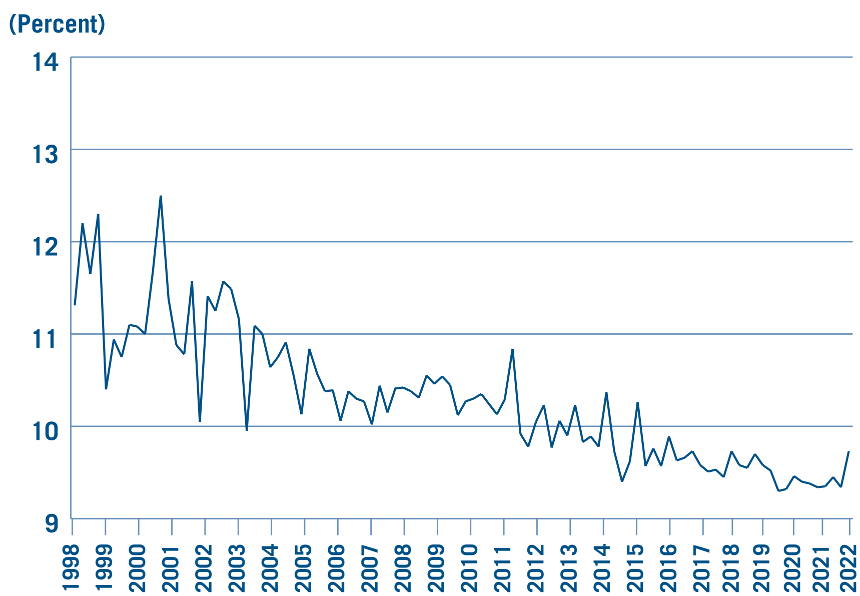
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

Average Awarded ROE 1998-2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

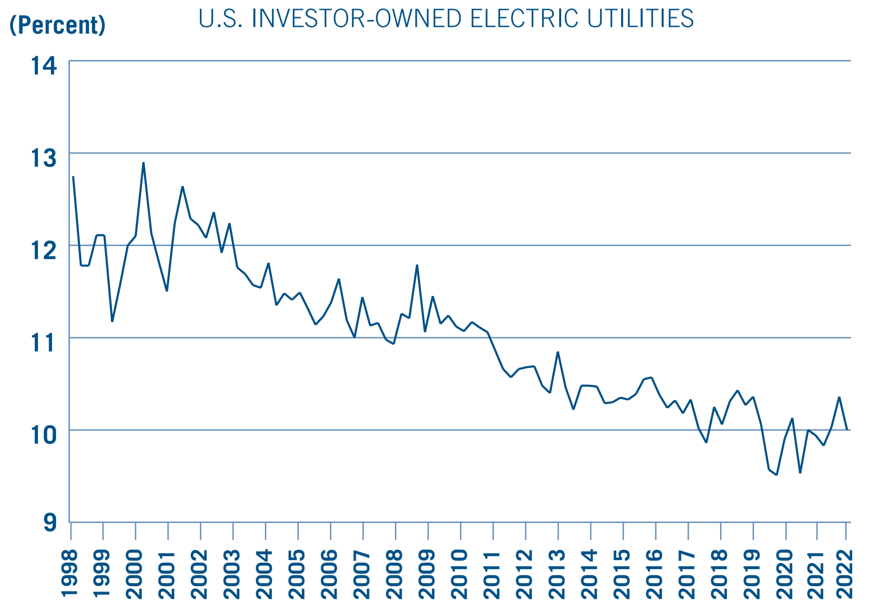


Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

- **Affordability** – The topic of affordability continues to play a significant role in rate review activity. Usually the result of settlement discussions, electric companies have either increased funding for their low-income programs, including arrearage forgiveness, bill credits/discounts, or weatherization programs. Some have even proposed new pilot programs, such as Percentage of Income Payment Plans, to address the increased attention to this issue. Several electric companies are also looking at ways to improve upon current program design and implementation processes by engaging with community action agencies and other interested stakeholders, making enrollment easier, and expanding access to programs.

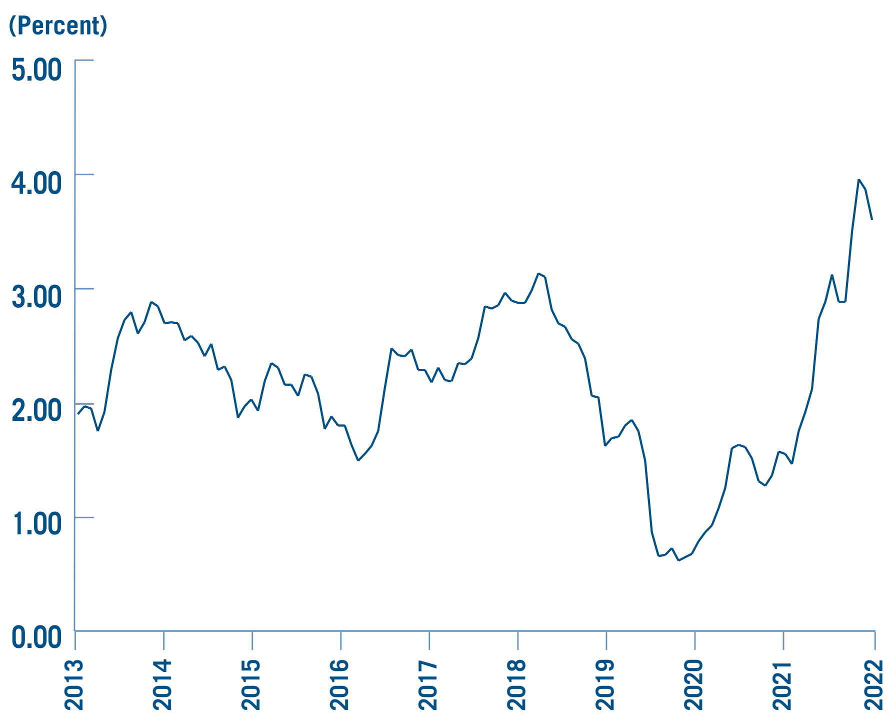
- **COVID-19 Cost Recovery** – The financial impacts of the pandemic are still being worked out in rate reviews. Many states issued orders allowing for deferral of COVID-related costs, for which electric companies are now seeking recovery. Most commonly, Commissions have authorized amortization of these costs over a two-to-five-year time frame. However, other companies have either been authorized to utilize test years that contain COVID-related costs or create a surcharge to recover costs from customers over a defined period of time. These costs are generally significant and in the millions of dollars, and we expect this issue will continue to come up as more electric companies file post-2020 rate reviews.

Average Requested ROE 1998–2022



Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

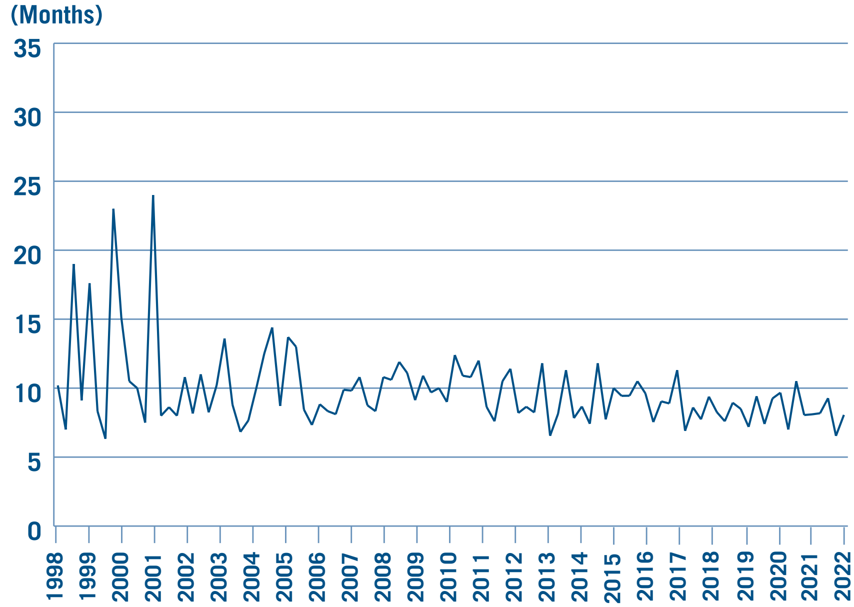
10-Year Treasury Yield
1/1/13 through 12/31/22



Source: U.S. Federal Reserve.

Average Regulatory Lag 1998–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

Finance, Accounting, and Investor Relations

The Finance, Accounting, and Investor Relations teams are part of EEI's Business Operations Group. This division provides the leadership and management for advocating industry policies, technical research, and enhancing the capabilities of individual members through education and information sharing. The division's leadership is used in areas that affect the financial health of the investor-owned electric utility industry, such as finance, accounting, taxation, internal auditing, investor relations, risk management, and budgeting and financial forecasting. If you need research information about these issue areas, please contact an EEI Finance, Accounting, or Investor Relations staff member (listed in this section). Under the direction of both the Finance and the Accounting Executive Advisory Committees, the division provides staff representatives to work with issue area committees. These committees give member company personnel a forum for information exchange and training and an opportunity to comment on legislative and regulatory proposals.

Publications

Quarterly Financial Updates

A series of financial reports on the investor-owned segment of the electric utility industry. Quarterly Financial Update (QFU) reports include stock performance, dividends, credit ratings, and rate review summary.

Financial Review

An annual report that provides a review of the financial performance of the investor-owned electric utility industry including the QFU topics mentioned above as well as the industry's consolidated financial statements. The report also includes an analysis in the areas of business segmentation, mergers & acquisitions, construction and fuel use by electric utilities.

EEI Index

Quarterly stock performance of the U.S. investor-owned electric utilities. The EEI index, which measures total return and provides company rankings for year to date and trailing one-year periods, is widely used in company proxy statements and for overall industry benchmarking.

Executive Accounting News Flash

Published quarterly and distributed to members of accounting committees, this update provides current information about the impact on our companies of evolving accounting and financial reporting issues. The News Flash is prepared jointly with AGA by the Utility Industry Accounting Fellow in coordination with our accounting staff in order to keep members informed on proposed and newly effective requirements from key accounting standard-setters.

Introduction to Depreciation for Utilities and Other Industries

Updated in 2013, the latest edition of this book serves as a primer on the concepts of depreciation accounting including fundamental principles, life analysis techniques, salvage and cost of removal analysis methods and depreciation rate calculation formulas and examples.

Conference Highlights

Financial Conference

This three-day conference is the premier annual fall gathering of utilities and the financial community; it is attended by more than 1,000 senior executives, including utility CEOs, CFOs, treasurers, investor relations executives, and Wall Street investment analysts, portfolio managers, commercial and investment bankers and the rating agencies. The General Sessions cover topics of strategic interest to the industry and financial community. Contact Jacob Moshel for more information.

Chief Financial Officers' Forum

This forum is held once a year in the fall in conjunction with the EEI Financial Conference. The forum provides an opportunity for chief financial officers to identify and discuss critical issues and challenges impacting the financial health of the electric utility industry. The forum is open to member company chief financial officers only. Contact Aaron Cope for more information.

Finance Committee Meeting

This day and a half meeting is held in the spring or summer. The meeting covers current and emerging industry issues critical to the electric power industry. It also provides an opportunity for utility financial officers to identify best practices and share management skills that contribute to financial performance. Contact Aaron Cope for more information.

Investor Relations Meeting

This one-day meeting is held in the spring. Executives gain insight on current and evolving industry issues, analysts' perspectives on the industry and have an opportunity to identify and share IR best practice concepts within and outside the electric utility industry. Contact Jacob Moshel for more information.

Treasury Group Meeting

Half day meetings are held in the spring and the fall annually. Discussion is focused on pension funding, capital markets and economic and regulatory impacts on debt and equity issuances. Members are provided an opportunity to share and identify best practices beneficial to the well-being of the industry. Contact Jacob Moshel for more information.

Accounting Leadership Conference

This annual meeting, held jointly with the Chief Audit Executives and their counterparts from AGA, covers current accounting, finance, business, and management issues for the Chief Accounting Officers and key accounting leadership of EEI member companies. Contact Randall Hartman for more information.

Chief Audit Executives Conference

This annual conference provides a forum for EEI and AGA Chief Audit Executives to discuss issues and challenges and exchange ideas on utility-specific internal auditing topics. The conference is open to members of the Internal Auditing Committee and other employees of EEI/ AGA member companies designated by the CAE. Contact Dave Dougher for more information.

Spring and Fall Accounting Conferences

Hosted by the EEI Corporate Accounting Committee, the Property Accounting & Valuation Committee, the Accounting Standards Committee, the Budgeting & Financial Forecasting Committee and the AGA Corporate Accounting and Property Accounting Committees, these conferences provide a forum for members to discuss current issues and challenges and exchange ideas in the electric and natural gas utility industries. The spring meeting is intended for all aforementioned committees, while the fall meeting is designed for the Corporate Accounting Committee and the Property Accounting & Valuation Committee. The meetings are open to members of the Committees and other employees of EEI/AGA member companies. Contact Dave Dougher for more information.

Taxation Committee Meeting

This three-day meeting is held every June and November, providing an opportunity for member company tax personnel to discuss technical information on utility tax issues. In addition to information exchange, members are briefed on current developments concerning major tax issues through presentations by committee members, outside tax specialists, and EEI staff. Contact Mark Agnew for more information.

Tax School

Hosted by the EEI Taxation Committee, this two- and half-day training is held every other year in the spring (The last two EEI Tax Schools were conducted as virtual meetings). The program is designed for tax managers and tax staff with two-plus years of tax experience or for financial accounting supervisors with tax responsibilities. The school is taught by a faculty of outstanding speakers from the accounting and legal professions as well as others from within the industry. Contact Mark Agnew for more information.

Accounting Courses

Introduction to Public Utility Accounting

This 4-day program, offered jointly with AGA, concentrates on the fundamentals of public utility accounting. It focuses on providing basic knowledge and a forum for understanding the elements of the utility business. It is intended primarily for recently hired electric and gas utility staff in the areas of accounting, auditing, and finance. Contact Randall Hartman or Dave Dougher for more information.

Advanced Public Utility Accounting

This intensive, 4-day course, jointly sponsored with AGA, focuses on complex and specific advanced accounting and industry topics. It addresses current accounting issues including those related to deregulation and competition, as they affect EEI member companies. Contact Randall Hartman or Dave Dougher for more information.

Property Accounting & Depreciation Training Seminar

The content from this seminar has been incorporated into the public utility accounting training courses described above and is no longer offered as a separate seminar. Contact Dave Dougher for more information.

Utility Internal Auditor's Training

Provides utility staff auditors, managers, and directors with the fundamentals of public utility auditing and specific utility audit/accounting issues including advanced internal auditing topics and is presented jointly by EEI and AGA – convenes for two and one-half days. Contact Randall Hartman or Dave Dougher for more information.

Additional Training Opportunities

Provides additional training opportunities as appropriate, such as Accounting for Energy Derivatives and FERC Accounting. Contact Randall Hartman or Dave Dougher for more information.

The EEI Business Services and Finance Division Staff

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jmoshel@eei.org

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Coordinator, Finance and Tax
(202) 508-5493
kking@eei.org

Edison Electric Institute Schedule of Upcoming Meetings

To assist in planning your schedule, here are upcoming meetings related to finance and accounting that may be of interest. For further details, contact Aaron Cope at (202) 508-5127, Randall Hartman (202) 508-5494, or Dave Dougher (202) 508-5570.

August 15-16, 2023
EEI/AGA Accounting Liaison Committee Meeting with FERC Staff
FERC Office
Washington, DC

August 28-30, 2023
EEI/AGA Utility Internal Auditor's Training Courses
Loews Atlanta Hotel
Atlanta, Georgia

August 28-31, 2023
EEI-AGA Introduction to Public Utility Accounting and Advanced Public Utility Accounting Training Courses
Loews Atlanta Hotel
Atlanta, Georgia

September 13-15, 2023
EEI/AGA Derivatives Training
Hyatt Rosemont
Chicago, Illinois

November 5-8, 2023
EEI/AGA Taxation Committee Meeting
San Diego, California

November 12-14, 2023
EEI Financial Conference
JW Marriott Desert Ridge
Phoenix, Arizona

November 12, 2023
EEI Treasury Group Meeting
(Closed meeting, admittance by invitation only)
JW Marriott Desert Ridge
Phoenix, Arizona

November 12, 2023
Chief Financial Officers Forum
(Closed meeting, admittance by invitation only)
JW Marriott Desert Ridge
Phoenix, Arizona

November 12-15, 2023
EEI/AGA Fall Accounting Conference
The Scott Resort & Spa
Scottsdale, Arizona

December (TBD), 2023
Investor Relations Planning Group Meeting
(Closed meeting, admittance by invitation only)
New York, New York

December (TBD), 2023
Wall Street Advisory Group Meeting
(Closed meeting, admittance by invitation only)
New York, New York

May 19-22, 2024
EEI/AGA Spring Accounting Conference
Philadelphia, Pennsylvania

June 23-26, 2024
EEI/AGA Accounting Leadership and Chief Audit Executives Conferences
TBD

U.S. Investor-Owned Electric Utilities

(At 12/31/2022)

ALLETE, Inc.
Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
AVANGRID, Inc.
Avista Corporation
Berkshire Hathaway Energy
Black Hills Corporation
CenterPoint Energy, Inc.
Cleco Corporate Holdings LLC
CMS Energy Corporation
Consolidated Edison, Inc.
Dominion Energy, Inc.
DTE Energy Company
Duke Energy Corporation
Edison International
Entergy Corporation
Evergy, Inc.
Eversource Energy
Exelon Corporation
FirstEnergy Corp.
Hawaiian Electric Industries, Inc.
IDACORP, Inc.
MDU Resources Group, Inc.
MGE Energy, Inc.
NextEra Energy, Inc.
NiSource Inc.
NorthWestern Corporation
OGE Energy Corp.
Otter Tail Corporation
PG&E Corporation
Pinnacle West Capital Corporation
PNM Resources, Inc.
Portland General Electric Company
PPL Corporation
Public Service Enterprise Group Inc.
Puget Energy, Inc.
Sempra Energy
Southern Company
The AES Corporation *
 DPL Inc.
 IPALCO Enterprises, Inc.
Unitil Corporation
WEC Energy Group, Inc.
Xcel Energy Inc.

Note: This list includes 39 publicly traded U.S. electric utility holding companies plus an additional five electric utilities (shown in italics) that are not listed on U.S. stock exchanges because they are owned by holding companies not primarily engaged in the business of providing retail electric distribution services in the United States.

* The AES Corporation is not included in the count of 39, but rather its two U.S. electric utility subsidiaries are included in the group of five italicized companies.

Other EEI Member Companies

Alaska Power & Telephone Company
American Transmission Company
Central Hudson Gas & Electric Corp.
Cross Texas Transmission
Duquesne Light Company
El Paso Electric
Florida Public Utilities
Green Mountain Power
ITC Holdings Corp.
Liberty Utilities
Mt. Carmel Public Utility Company
National Grid
Ohio Valley Electric Corporation
Sharyland Utilities
Tampa Electric an Emera Company
UGI Corporation
UNS Energy Corporation
Upper Peninsula Power Company
Vermont Electric Power Company

Note: These companies are not included in the EEI Financial Review data sets for one of the following reasons: they do not provide retail electric distribution service (i.e., transmission-only), they are subsidiaries of foreign-owned companies, they are not traded on a major U.S. stock exchange, or they are owned by a non-utility holding company and the granularity of publicly available financial data is insufficient.

The **Edison Electric Institute** (EEI) is the association that represents all U.S. investor-owned electric companies. Our U.S. members provide electricity for 220 million Americans and operate in all 50 states and the District of Columbia. EEI also has dozens of international electric companies as International Members, and hundreds of industry suppliers and related organizations as Associate Members.

Safe, reliable, affordable, and increasingly clean energy enhances the lives of all Americans and powers the economy. As a whole, the electric power industry supports more than 7 million jobs in communities across the United States and contributes 5 percent to the nation's GDP.

Organized in 1933, EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums.

For more information, visit our Web site at **www.eei.org**.

EEI
Edison Electric Institute
701 Pennsylvania Avenue, NW
Washington, DC 20004-2696
202-508-5000 | www.eei.org

CASE: UE 416
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2909

Public Comments
Received After Staff Opening Testimony

August 22, 2023

From: SPENST Carissa * PUC
To: PUC PUC.PublicComments * PUC
Subject: Anonymous PGE customer - Late Notices
Date: Thursday, June 22, 2023 10:06:18 AM

Customer called and said he would like to have his comments put on the record regarding receiving urgent late notices in red envelopes from PGE.

He said that he's had service for over 30 years, and over the last year he's noticed that if he's 3 or 4 days late paying his bill, he gets an envelope in the mail with big red letters telling him it's an urgent notice from PGE regarding his account.

He said that he called PGE this morning to ask why they're doing this because he also gets phone calls and feels it's a waste of time and energy and effort for them to do this. PGE told him that it's something that the OPUC requires them to do.

So he called to find out if that's true or not. I explained to him that yes, the regulated utility companies are required by the OAR's to send late notices in the mail to customers as soon as the due date has been missed. The calls are a customer service effort by the company and are not required.

He said he thinks it's a waste of time and shouldn't be done because it's a lot of effort just to keep the people involved in the whole process employed. He said he wants his comments added to the record.

Thank you,

Carissa M. Spenst

Carissa M. Spenst
Compliance Specialist
Oregon Public Utility Commission
Puc.consumer@puc.oregon.gov
1-800-522-2404/503-378-6600
503-378-5743 (fax)

From: Cierra
To: PUC PUC.PublicComments * PUC
Subject: Comments on UE 416 (1)
Date: Tuesday, May 23, 2023 4:56:40 PM

This increase is wrong. The rise of fossil fuel costs should not rely on working families pockets. We are not customers paying for a luxury service, you are not a streaming service, or a gym membership. This is a UTILITY company. Electricity is a right. Parents can lose their children for not having electricity. Rental Management companies can fine families or even take their homes for simply being late on their bill. I find it hard to believe the offset of costs cant be supplemented by the millions of dollars in tax breaks and CEO salaries. For the industry to continue to rely on fossil fuels at the expense of the public is atrocious.

Cierra Coppedge
Ccfrogger87@yahoo.com

From: Natalia Neal
To: PUC PUC.PublicComments * PUC
Subject: Comments on UE 416 (2)
Date: Tuesday, May 23, 2023 4:27:02 PM

Hello,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, a 16% rate increase will have a big impact on my household.

I live in a house, and I'm low income. A $23 increase is a big deal for me. Inflation has already increased my grocery bills and other household expenses. No one should have to choose between electricity, rent, medication, and food.

At a time of continued historic inflation, raising bills this much will have negative impacts on low-income Oregonians.

I urge the Commission to reduce this increase wherever possible.

Sincerely,

Natalia Neal

17373 SE Forest Hill Drive

Damascus, OR 97089

From: margiemcclure@comcast.net
To: PUC PUC.PublicComments * PUC
Subject: Comments on UE 416 (3)
Date: Thursday, May 25, 2023 2:28:56 AM

My Food Stamps barely get me 1 week's worth of groceries now days. And i hear you might increase single dwellings more, unless apartments in large buildings qualify us a multiple dwellings? Why do you all keep raising the things we can't really control? Its' not like we can just stop using electricity! I feel like we are being held up - everywhere! First they came for my food stamps, when the federal government stopped that extra $$ a few months ago, even as food prices are soaring. Rent is about to go up too and just the overall cost of living. The last thing people like me need, is a ballooning, out of control energy bill on top of everything else. Please reconsider! Thank You! margie

margiemcclure

From: Kristy Stephens
To: PUC PUC.PublicComments * PUC
Subject: Comments on UE 416 (4)
Date: Thursday, June 1, 2023 7:25:08 PM

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Kristy S.
Concerned Oregonian

From: Martin McCurdy
To: PUC PUC.PublicComments * PUC
Subject: Comments on UE 416
Date: Tuesday, May 23, 2023 4:19:09 PM

Do not raise PGE bill! I am on a low fixed income, live in Multnomah County and cannot afford it.

-Martin McCurdy

-

Sent from my iPhone

From:	SILVIA TANNER
To:	PUC PUC.PublicComments * PUC
Cc:	John Wasiutynski; MOSER Nolan * PUC
Subject:	Docket No. UE 416 - Comments by Multnomah County
Date:	Wednesday, May 31, 2023 5:08:21 PM
Attachments:	Multnomah County Rate Case Comments 20220526.pdf

Dear AHD staff,

Please see attached the Comments by Multnomah County Chair Jessica Vega Pederson related to PGE's proposed rate increase in Docket No. UE 416.

Please let me know if you have any comments or questions.

Best,

Silvia Tanner

--
Silvia Tanner, JD *(pronouns she/her)*
Sr. Energy Policy and Legal Analyst

Office of Sustainability | Multnomah County

501 SE Hawthorne Blvd., Suite 600, Portland, OR 97214

T: 503.988.4092 | W: Office of Sustainability

From: PUC CONSUMER PUC * PUC
To: PUC PUC.PublicComments * PUC
Subject: FW: Request for Automatic Support for Low-Income Households in PGE Rate Changes
Date: Monday, June 12, 2023 9:54:51 AM

From: T.J Graven <tjgraven7773@gmail.com>
Sent: Saturday, June 10, 2023 7:44 PM
To: PUC CONSUMER PUC * PUC <puc.consumer@puc.oregon.gov>
Subject: Request for Automatic Support for Low-Income Households in PGE Rate Changes

You don't often get email from tjgraven7773@gmail.com. Learn why this is important

Tiffiny Graven
Portland, Oregon 97215
Tjgraven7773@gmail.com
971-307-7829
June 2023

Oregon Public Utility Commission
P.O. Box 1088
Salem, OR 97308-1088

Dear Oregon Public Utility Commission,

I hope this letter finds you in good health and high spirits. I am writing to express my concerns regarding the proposed price increases by Portland General Electric (PGE) and to request your consideration for implementing automatic support for low-income households in the rate changes.

As a resident of Portland, Oregon, I am deeply concerned about the impact these price increases may have on the affordability of housing for low-income families. It is crucial that we ensure access to essential services, such as electricity, for all residents, regardless of their income level. I believe that by introducing separate billing and automatic support for low-income households, we can address this pressing issue and mitigate the burden on vulnerable communities.

Separate billing for low-income households would allow for a more equitable distribution of costs, ensuring that those who are already struggling to afford housing are not burdened further by increased electricity prices. By implementing a system where families can provide proof of their low-income status, they can be automatically enrolled in a support program that helps alleviate the financial strain of their utility bills.

I kindly request that the Oregon Public Utility Commission thoroughly consider this proposal during the review of PGE's rate changes. By incorporating automatic support for low-income households, we can uphold the principle of fairness and work towards creating an inclusive and supportive community for all residents.

Additionally, I would like to express my interest in participating in any public hearings or submitting written comments regarding this matter. Please inform me of any upcoming opportunities for public input, as I am committed to voicing my concerns and contributing constructively to the decision-making process.

Thank you for your attention to this matter. I trust that the Oregon Public Utility Commission will diligently consider the impact of these proposed price increases on low-income households and take necessary steps to ensure affordability and accessibility of essential utilities.

Yours sincerely,

Tiffiny Graven
Tjgraven7773@gmail.com
971-307-7829

From: Kathleen Bisom
To: PUC PUC.PublicComments * PUC
Subject: Impact -PGE
Date: Friday, June 9, 2023 8:13:01 PM

You don't often get email from katwilson0i812@gmail.com. Learn why this is important

Hello & thank you for caring what the public, Your Customers think. Any rate increase would have a negative impact on me & my family. With the food prices have doubled since the beginning of the covid pandemic has & is taking a toll on our family & our saving we once had is now gone just to continue eating healthy home cooked meals. We cannot & we do not eat out , we are unable to afford such plus eating out is not too healthy of a choice. My family & I live on a fixed budget and as soon as government got their citizens excited about getting a raise the highest raise ever given, the government raises food products , necessities for living, & existing doubling in price. So you see we are barely staying afloat. Rent increase property tax increase, gas price increase, increase prices for water, sewer, garbage services, list continues but I'm its the same impact for everyone. Trying to live on a below poverty level income is challenging. And we'll get by with God's help paying any increase PGE may enforce. We, my family uses less energy than neighboring homes so we'll have to be more frugal in usages of power. Thank you for your time, & understanding. Good luck

Kathleen Bisom

From: Oliveira, Donnie
To: PUC PUC.PublicComments * PUC
Subject: INFO: Docket No. UE 416 Public Comment
Date: Wednesday, May 31, 2023 4:29:10 PM
Attachments: City of Portland-Docket No. UE 416.pdf

Please see attached.

Donnie Oliveira, he/him/his
Director
City of Portland Bureau of Planning and Sustainability
Phone: 503.593.1869
www.portlandoregon.gov/bps | Twitter | Facebook

The City of Portland is committed to providing meaningful access. For accommodations, modifications, translation, interpretation or other services, please contact at 503.823.7700 or use City TTY 503.823.7700

From: RICHTER Brandy * PUC
To: PUC PUC.PublicComments * PUC
Subject: Klaus Pagel - PGE public comment UE 416
Date: Tuesday, June 27, 2023 1:11:26 PM

Klaus Pagel worked for Yamhill County for 30 years. He is requesting to submit his public comment about PGE rates.

He would like to see the rates determined off income rather than based on usage. Older people such as himself have a static income, and when the rates increase, it is not something that they are able to adjust and account for in their income. Especially when the rate increase comes in the winter months. Older people would be able to manage it easier if the rates were based off income. He knows that California has made an effort to charge based on household income, which results in a reduction of the billable amount for lower income households.

If he gets a say, he would like to vote for no increases at all, but he is really requesting a shift in the billing practices.

I let him know that PGE has a relatively new income qualified bill discount program. He was not aware of the program and said he was going to check if he qualified. He has not spoken to them since before the program was brought online.

Thank you,

Brandy Richter

Compliance Specialist

BRANDY.RICHTER@PUC.OREGON.GOV

503-378-6600/1-800-522-2404

From: Francine Kaufman
To: PUC PUC.PublicComments * PUC
Subject: NO ON THE PGE RATE INCREASE
Date: Saturday, May 27, 2023 7:41:30 AM

I strongly oppose the proposed PGE rate increase for the following reasons:
1. It would effectively cancel out the low income discount for residential customers like me and others like me.
2. The Community Energy Project recommends opposing this.
3. It's very poor timing for all customers and might have a negative impact on the low income discounts residential customers receive from the Community Solar Program and discourage residential renewable energy efforts in Oregon
4. It would hit residential low income customers the hardest.
5. PGE would be better off saving money by doing away with it's free gift card drawing programs to encourage residential customers for taking service related surveys. That I am sure generates unecessary expense to PGE that passes along those costs to its customers that aren't the fortunate few who win them. It is an irresponsible use of funds and an unfair and misleading ploy for a PGE pr and marketing program that is unethical and takes advantage of many of it's customers.

Sent from Frontier Yahoo Mail on Android

From: Mara Monroe
To: PUC CONSUMER PUC * PUC
Subject: PGE 14% Rate Increase Proposal
Date: Wednesday, May 31, 2023 1:36:34 PM

To Whom It May Concern:

I am writing in regard to the proposal by PGE to raise rates up to 14% in 2024. We're PGE customers and do not support any rate increase.
A rate increase would impact our family by making it harder to balance our budget and have any money for unexpected monthly expenses.
Our employers are not offering raises that would offset any rate increases, and inflation has made it so everyday expenses overwhelm our bank account.

We're in the Milwaukie area and experienced a 5 day power outage in 2021 due to an ice storm. We're aware that power providers may face more threats due to extreme weather and climate change.
Just two days ago, on Memorial Day 2023, our area experienced an outage lasting 5.5 hours. This affected over 1000 households according to the PGE outage map.
We had just purchased groceries that morning and because of the power loss, most of our perishable items had to be discarded. We understand that emergencies come up, but it's the end of the month and rent is due in three days. We cannot afford to re-purchase food and have to pay rent. These type of choices could become more typical if electrical bills continue to rise,along with costs for other utilities that also incur rate increases, such as our monthly water bill.

I understand that power cannot be free, and PGE has been reliable, but I don't think consumers should bear the challenge of paying for it. I'm sitting here trying to figure out what to feed my family because we have to stretch and scrape because something unexpected came up.

I strongly urge PGE to look to find other ways to meet the costs of providing power.

Signed,

Michelle Perry, Milwaukie, Oregon

From:	Travis Geist
To:	PUC PUC.PublicComments * PUC
Subject:	PGE rate increase (1)
Date:	Thursday, May 4, 2023 4:34:11 PM

I’m against this, especially when they’re asking for 14% and I already pay a premium after switching to a heat pump. Not to mention their monopoly on power. This is stupid

From: Emma Keller
To: PUC CONSUMER PUC * PUC
Subject: PGE Rate Increase 2024
Date: Wednesday, May 31, 2023 1:07:52 PM

Hello,

I'm contacting the Oregon Public Utility Commission regarding the proposed PGE rate increase of 14% for 2024. I'm a PGE customer and currently live in a rental apartment.
I'm strongly opposed to this rate increase and feel that it would place additional challenges on households currently struggling to make ends meet. My family of three currently gets by on a single income. Even with the assistance of the PGE discount program, our monthly bill is between $150-$170 a month. We're spending more on utility bills than our food, and each year we await an expected rent increase. For 2023, landlords were allowed a maximum rent increase of 14.6%. Our lease, which renews in August, went up by $150.
We're facing a crisis of rising prices and wages that haven't been raised to meet them. PGE's proposal will add an extra burden to households and increase our bills. Each month someone might have to do the balancing act of either paying the bills or providing food or medical needs for their family.
PGE needs to work to find a better solution to meet energy needs. Placing the cost on the customers is not just financial; it encompasses mental health, basic needs, and an infrastructure that has little assistance to those who need help.

Sincerely,

Emma Kellar

From: Mark Habib
To: PUC PUC.PublicComments * PUC
Subject: PGE rate increase comment
Date: Wednesday, June 21, 2023 1:10:13 PM

You don't often get email from markdhabib@gmail.com. Learn why this is important

Hi,

I am a PGE customer. I strongly disagree with a rate increase. Previous rate increases have been justified by increased natural gas prices. Natural gas prices have fallen dramatically this year, to a level not seen since 2021. Multiple rate increases have already occurred between 2021 and now, so not only is a current rate increase unreasonable, what would actually be appropriate is a rate decrease. I beg upon the PUC to reject this rate increase. This rate increase would further subject PGE customers, such as myself and my family, to hardship in order to increase PGE's profits. People over profit. Again, a rate decrease is in order, and ideally PGE would be subject to punitive action for this unjustified money grab, but I know you won't actually do that. I don't have much more to say, but please consider the facts and the delicate financial situation that many Oregonians are already in.

Thank you,
Mark Habib
6403 SE 92nd Ave
Portland, OR 97266

From: morteza rezaee babak
To: PUC PUC.PublicComments * PUC
Subject: PGE rate increase
Date: Monday, June 12, 2023 8:26:57 PM

Hello,

As a PGE customer, I feel frustrated and powerless. I understand the need for rate increase from time to time. But this is second year in a row that we have rate increase.
PGE is already has the highest rates in the state despite having the smallest network. Maybe they should lower the greed and higher the efficiency.
Please consider that many of us are currently facing financial hardship due to inflation.

Thank you,
Morteza

From: CONNEY BEAUDRY
To: PUC PUC.PublicComments * PUC
Subject: PGE rate increases docket #UE 416
Date: Wednesday, June 14, 2023 4:32:25 PM

It is a terrible idea for PGE to increase rates on the public. We already had an increase this past year of 7 percent and now to ask people to pay more again is ridiculous!
I did not get a pay increase this year so how can you expect people to keep up with their utility bills.
It is a greedy money grabbing way and instead of helping the public this is their answer?
The cost of everything is so bad. We are not poor but middle income and are struggling.
The utility commission needs to stand up and say no!
C Beaudry

From: sueb
To: PUC CONSUMER PUC * PUC
Subject: Pge request
Date: Thursday, May 4, 2023 12:32:15 PM

No way they need 14%. That is beyond inflation to start with. It's beyond what is affordable. Let's look at higher administrative salaries and their salarieswith bonuses. This cannot be approved in any way
Susan Brewer

Sent via the Samsung Galaxy S21+ 5G, an AT&T 5G smartphone

From: Rebecca B
To: PUC PUC.PublicComments * PUC
Subject: Proposed PGE Price Increase (1)
Date: Thursday, June 8, 2023 2:47:40 PM

I would like to submit my opposition to the proposed PGE rate increase taking effect this January 2024.

Consumers are being squeezed enough with inflation - which is mostly caused by corporations increasing prices just because they can. Our electricity company should not fall into that category.

Thank you,
Rebecca Britton

From: Rebecca B
To: PUC CONSUMER PUC * PUC
Subject: Proposed PGE Price Increase
Date: Wednesday, May 31, 2023 1:04:08 PM

I would like to submit my opposition to the proposed PGE rate increase taking effect this January 2024.

Consumers are being squeezed enough with inflation that we know is mostly caused by corporations increasing prices just because they can. Our electricity company should not fall into that category. PGE can raise rates after inflation goes down.

Thank you,
Rebecca Britton

From: derek.sanborn7@gmail.com
To: PUC PUC.PublicComments * PUC
Subject: Proposed PGE rate increase
Date: Thursday, May 4, 2023 4:58:50 PM

To whom it may concern:

Why would residents pay more than industrial users? We just had a rate increase of 7% last year and now already looking at 14% more? $233mm net income last year isn't enough? This is a money grab that I disagree with being instituted and will make it harder for people to cover their bills that are still dealing with persistent inflation and rising rents, among others.

Sent from my iPhone

Sent from my iPhone

From:	Julie Blackman CTC
To:	PUC PUC.PublicComments * PUC
Subject:	Proposed PGE Residential Rate Increase
Date:	Wednesday, May 31, 2023 11:39:28 AM

-

As a residential customer of PGE I strongly oppose the proposed substantial increase in residential rates - particularly for those in single-family housing.

PGE has received rate increases in ever increasing amounts. This most recent proposal, which is projected to add about $22 per month to the typical household, is just about the last straw for many households. It comes on top of a non-negligible increase in 2022.

While we work diligently to limit our power usage, there is only so much that can be done. At a certain point safety, security and comfort are sacrificed in order to hold the line on utility bills. An increase of 16% will be a burden for many households.

I understand and applaud PGE's attention to improved maintenance and particularly prevention of wildfire via technology and maintenance.

However, said expenses could easily come from shareholder dividends and some of the enormous salaries enjoyed by PGE officers. Said officers earn enough that they don't understand the impact on the typical household on the increases. They could probably manage if their bonuses and salaries were slightly lower this year rather than shifting all the expense to their captive customers.

The requested increase is roughly twice the rate of inflation. PGE has not demonstrated the reasonableness of such a large rate hike.

I urge the PUC to do its job and deny this increase.

Thank you for your attention to these concerns.

Sincerely,

Julie Blackman

From: Admin
To: PUC PUC.PublicComments * PUC
Subject: protest of proposal - PGE
Date: Saturday, June 17, 2023 9:28:55 PM

You don't often get email from danielle.robillard@comcast.net. Learn why this is important

Hello,

PGE wants to raise my rate because they were operating so badly that they caused wildfires?

I do NOT think so -

I and a lot of my fellow Oregonians live paycheck to paycheck - and funding a corporate foul-up - no matter how awful it was, is simply not in my budget!!!

Please do not make me cut back on my minuscule food budget because PGE is unaware of its job and responsibilities.

Thank you for reading my comment,

Danielle Robillard
Troutdale OR

From:	Hale, Matthew
To:	PUC PUC.PublicComments * PUC
Subject:	Public Comments on UE 416 (13)
Date:	Friday, May 26, 2023 1:42:50 PM

Comments on Proposed Rate Increase by PGE – UE 416

Oregon Public Utility Commission
Attn: AHD – UE 416
PO Box 1088
Salem, OR 97308

I strongly recommend that before deciding on PGE's 14 percent proposed rate increase affecting ratepayers, that the OPUC consider all the taxes and fees the average ratepayer pays on their monthly PGE electric bill. On our monthly bill, those "regulatory charges, taxes and fees" account for a 17.9% additional charge on our "energy charges." According to the Federal Reserve study released this Monday, "American families did worse financially last year than they did the year before, as inflation and the evaporation of federal stimulus money began to weigh on household budgets." In addition, the study found that "More than one-third of respondents—or 35%—said they were worse off financially in 2022 than in 2021, marking the highest level since the Fed began asking the question in 2014."

Are there any potential cost savings that the OPUC could consider to assist ratepayers, specifically the monetary value of the Renewable Energy Certificates (RECs) PGE has been accumulating since Oregon enacted the Renewable Portfolio Standard (RPS)? I understand that sometime in 2011 or 2012, PGE and Pacific Power benefited from a decision to award them RECs as their renewable generators were registered in the Western Renewable Energy Generation Information System (WREGIS). These initial RECs were at the time called stranded generation, as described in a report commissioned by the Center for Resource Solutions (CRS). The report "arranged for WREGIS to create RECs retroactively for stranded electricity. Under this arrangement, all RECs created through this process must be exclusively used for Oregon RPS compliance."

Perhaps these RECs, and their corresponding monetary value, could be used to offset the 14% proposed rate increase and provide some much-needed financial relief to rate payers?

Thank you for your consideration.

Sincerely,

Matt Hale

Salem, OR

From: anna.gonzales80@everyactioncustom.com on behalf of anna gonzales
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (1)
Date: Saturday, May 20, 2023 9:57:12 AM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
anna gonzales
15928 NE Fremont St Portland, OR 97230-5120
anna.gonzales80@yahoo.com

From: anna.gonzales80@everyactioncustom.com on behalf of anna gonzales
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (2)
Date: Saturday, May 20, 2023 9:57:25 AM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
anna gonzales
15928 NE Fremont St Portland, OR 97230-5120
anna.gonzales80@yahoo.com

From: anna.gonzales80@everyactioncustom.com on behalf of anna gonzales
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (3)
Date: Saturday, May 20, 2023 9:58:29 AM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
anna gonzales
15928 NE Fremont St Portland, OR 97230-5120
anna.gonzales80@yahoo.com

From: ser.myhome@everyactioncustom.com on behalf of In Ser
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (4)
Date: Tuesday, May 23, 2023 3:44:30 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
In Ser
16265 SW Mason Ln Beaverton, OR 97006-5579
ser.myhome@gmail.com

From: oweisahed@everyactioncustom.com on behalf of Ahed Oweis
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (5)
Date: Tuesday, May 23, 2023 3:47:09 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

We hope not to increase the bills because that will have very bad impact on our family.

Sincerely,
Ahed Oweis
10837 SE Cherry Blossom Dr Portland, OR 97216-3107
oweisahed@gmail.com

From: lilalee@everyactioncustom.com on behalf of Lila Lee
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (6)
Date: Tuesday, May 23, 2023 3:50:36 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Lila Lee
900 SW Cheltenham St Portland, OR 97239-2606
lilalee@teleport.com

From: careydog@everyactioncustom.com on behalf of Carey Lee
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (7)
Date: Tuesday, May 23, 2023 4:04:56 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

I am already on a very limited budget, and this huge rate increase will be devastating. Climate change is already significantly affecting the Willamette Valley and we will need to rely even more on electricity to deal with the severe climate/weather consequences. Rate payers have a legitimate need to access affordable service. Our food costs are rising and will surely keep increasing as the Colorado river (& other water sources) continue to dry up.

While shareholders/capitalism makes the world go round, the proposed rate increase is way too much! We are looking at huge temperature changes and profiting off this surely not moral.

Thank you for the opportunity to address the Commissioners. Please reduce this increase to reflect the needs of all of us.

Sincerely,
Carey Lee
3202 Bluff Ave SE Apt 17 Salem, OR 97302-3284
careydog@gmail.com

From: ethanvoon@everyactioncustom.com on behalf of ETHAN VOON
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (8)
Date: Tuesday, May 23, 2023 4:18:47 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm deeply concerned about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing an almost $23 per month increase. My family lives in a house and we are middle income, a $23 increase is a big deal for us. Inflation has already increased our grocery bills and many other household expenses.

I can only imagine how detrimental this will be on those with even less income than my household. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
ETHAN VOON
1621 N Church St Portland, OR 97217-4514
ethanvoon@outlook.com

From:	tjzendlessobsessions@everyactioncustom.com on behalf of Travis Johnston
To:	PUC PUC.PublicComments * PUC
Subject:	Public Comments on UE 416 (9)
Date:	Thursday, May 25, 2023 1:38:23 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I’m worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Travis Johnston
4707 SE Boardman Ave Apt 19 Portland, OR 97267-5937
tjzendlessobsessions@gmail.com

From: Natasha_vdn@everyactioncustom.com on behalf of Natalia Neal
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (10)
Date: Tuesday, May 23, 2023 4:24:38 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I’m worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Natalia Neal
17373 SE Forest Hill Dr Damascus, OR 97089-2751
Natasha_vdn@yahoo.com

From: Natasha_vdn@everyactioncustom.com on behalf of Natalia Neal
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (11)
Date: Tuesday, May 23, 2023 4:24:39 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Natalia Neal
17373 SE Forest Hill Dr Damascus, OR 97089-2751
Natasha_vdn@yahoo.com

From: ruthierocha10@everyactioncustom.com on behalf of Ruth Rocha
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (12)
Date: Tuesday, May 23, 2023 4:27:02 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Ruth Rocha
4815 Bayne St NE Salem, OR 97305-3589
ruthierocha10@yahoo.com

From: jrocha1289@everyactioncustom.com on behalf of Joshua Rocha
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (14)
Date: Tuesday, May 23, 2023 4:29:21 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Joshua Rocha
5119 Countryside St NE Apt 104 Salem, OR 97305-4164
jrocha1289@yahoo.com

From: ccfrogger87@everyactioncustom.com on behalf of Cierra Coppedge
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (15)
Date: Tuesday, May 23, 2023 4:54:09 PM

Dear Oregon Public Utility Commission,

This increase is wrong. The rise of fossil fuel costs should not rely on working families pockets. We are not customers paying for a luxury service, you are not a streaming service, or a gym membership. This is a UTILITY company. Electricity is a right. Parents can lose their children for not having electricity. Rental Management companies can fine families or even take their homes for simply being late on their bill.I find it hard to believe the offset of costs cant be supplemented by the millions of dollars in tax breaks and CEO salaries. For the industry to continue to rely on fossil fuels at the expense of the public is atrocious.

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Cierra Coppedge
8043 SE Monroe St Portland, OR 97222-1169
ccfrogger87@yahoo.com

From: aex3@everyactioncustom.com on behalf of David Abraham
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (16)
Date: Saturday, May 27, 2023 9:10:44 AM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact me personally.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

My PGE rates have more than doubled in the last year, and I am not using any more power. Most months I am using less to try and reduce cost. I am a single individual living alone, yet even with 40% low income discount and additional utility aid, my monthly bills exceed $100. Now PGE wants to raise rates even more.

With rotting power poles and crumbling insulation on power lines in my neighborhood, there are no visible improvements being made to the infrastucture in my area.

I am barely making it month to month. I only heat my home to 64 degrees and have no air conditioning to endure the summer heat. An increase will put me into the negative even further.

I urge the Commission to reduce this increase wherever possible and take a hard look at exactly how PGE is spending their funds. Thank you for your consideration.

Sincerely,
David Abraham
1615 SE Oak Shore Ln Oak Grove, OR 97267-3627
aex3@outlook.com

From: lepermag@everyactioncustom.com on behalf of LeAnn Pinniger Magee
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (17)
Date: Tuesday, May 23, 2023 5:04:42 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
LeAnn Pinniger Magee
6607 SW Florence Ln Portland, OR 97223-9223
lepermag@gmail.com

From: sky.karen@everyactioncustom.com on behalf of Karen Sky
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (18)
Date: Tuesday, May 23, 2023 5:26:27 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

My Single-family home is facing a $22.71 per month increase. I am a Senior who lives alone and am on Social Security. This much cost added to my electric bill means this much less I have for food each month. Food prices have sky rocketed and it is difficult to find sales on groceries and still find food that is healthy for my advanced age. Adding this much money to electric bills will force me to choose between other household expenses. No one should have to choose between electricity, rent, water, medication, and food.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Karen Sky
3805 SE Drake St Portland, OR 97222-5850
sky.karen@gmail.com

From: erzulie7@everyactioncustom.com on behalf of andrea flores
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (19)
Date: Tuesday, May 23, 2023 6:19:16 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
andrea flores
9463 N Saint Louis Ave Portland, OR 97203-2272
erzulie7@aol.com

From: erzulie7@everyactioncustom.com on behalf of ursula flores
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (20)
Date: Tuesday, May 23, 2023 6:20:52 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household. We struggle to pay our utilites now and receive help every year. How will we afford this?!

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
ursula flores
9463 N Saint Louis Ave Portland, OR 97203-2272
erzulie7@aol.com

From: marytfree@everyactioncustom.com on behalf of Mary Freeman
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (21)
Date: Tuesday, May 23, 2023 6:57:56 PM

Dear Oregon Public Utility Commission,

Regarding rate increase with UE 416 I am writing to submit comments on how this would affect my household. I am a single (widowed) disabled parent. My daughter (in my household) is 17yr. She plans on living with me while going to college and we will only have my social security money to pay bills and rent and every other bill you can imagine it will be so difficult in paying a large portion of our already tight budget towards increased rates - electricity.
I already freeze all winter because I can't afford to keep our unit as warm as I'd like it to be which affects my medical conditions but I honestly don't have a choice, I struggle in paying the bill as it is and being extremely frugile on usage. Please don't raise our rates so high with the PGE rate case (UE 416). I worry so much about food costs as it is, the rate of inflation is out of control. I get limited food stamps. I can't afford any luxury like cable. I cut corners all the time due to necessity. I go to food banks as often as allowed.
Please consider the low income families and the retired the elderly and the disabled. I already freeze due to the bill and how hard it is to pay.

I heard this would be the largest rate hike in 20 years, raising bills this much will have real impacts on Oregonians. Very negative.
I understand the homelessness issue, I don't judge them. With rents skyrocketing and electricity and gas and food. People simply can't afford to make it.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Mary Freeman

Sincerely,
Mary Freeman
1412 N Deborah Rd Apt 38 Newberg, OR 97132-2073
marytfree@gmail.com

From: ggbb503@everyactioncustom.com on behalf of Gary Brown
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (22)
Date: Tuesday, May 23, 2023 11:31:30 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Gary Brown
2127 SE 155th Ave Portland, OR 97233-3459
ggbb503@gmail.com

From: ggbb503@everyactioncustom.com on behalf of Gary Brown
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (23)
Date: Tuesday, May 23, 2023 11:31:42 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Gary Brown
2127 SE 155th Ave Portland, OR 97233-3459
ggbb503@gmail.com

From: ggbb503@everyactioncustom.com on behalf of Gary Brown
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (24)
Date: Wednesday, May 24, 2023 1:00:24 AM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Gary Brown
2127 SE 155th Ave Portland, OR 97233-3459
ggbb503@gmail.com

From: sherryjo29@everyactioncustom.com on behalf of Charles Jones
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (25)
Date: Wednesday, May 24, 2023 7:25:50 AM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Charles Jones
2340 SW 15th St Gresham, OR 97080-9703
sherryjo29@msn.com

From: hladikgh@everyactioncustom.com on behalf of Gabrielle Hladik
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (26)
Date: Wednesday, May 24, 2023 7:53:09 AM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I’m worried about how a 16% rate increase for residential customers will impact my household.
I live in an apartment and I’m low income. A $15/mo increase is a big deal for me. Inflation has already increased my grocery bills and other household expenses. No one should have to choose between electricity, rent, medication, and food.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible because continuously abusing our wallets and livelihoods is horrid. Thank you for your consideration.

Sincerely,
Gabrielle Hladik
6134 SW 18th Dr Portland, OR 97239-1993
hladikgh@gmail.com

From: hladikgh@everyactioncustom.com on behalf of Gabrielle Hladik
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (27)
Date: Wednesday, May 24, 2023 7:53:38 AM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Gabrielle Hladik
6134 SW 18th Dr Portland, OR 97239-1993
hladikgh@gmail.com

From: elizabethpochardt@everyactioncustom.com on behalf of Elizabeth Pochardt
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (28)
Date: Wednesday, May 24, 2023 10:16:39 AM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416).

As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household. I'm a first time homebuyer, living paycheck to paycheck-an additional $22 a month would be an entire hour's wage for me. I'm already in debt with medical bills, etc. & have barely bought groceries in a month. This is a very hard time for many of us.

I urge the Commission to reduce this increase wherever possible. Maybe offering more off-grid solar options for low income households? Thank you for your consideration.

Sincerely,
Elizabeth Pochardt
7530 SW Barnes Rd Portland, OR 97225-6232
elizabethpochardt@gmail.com

From: taylor.stephenson28@everyactioncustom.com on behalf of Taevon Reyna
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (29)
Date: Wednesday, May 24, 2023 11:09:21 AM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

I live in an apartment and I'm low income. A $15/mo increase is a big deal for me. Inflation has already increased my grocery bills and other household expenses. No one should have to choose between electricity, rent, medication, and food.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

Sincerely,
Taevon Reyna
247 SE 160th Ave Apt A207 Portland, OR 97233-3589
taylor.stephenson28@gmail.com

From: taylor.stephenson28@everyactioncustom.com on behalf of Taevon Reyna
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (30)
Date: Wednesday, May 24, 2023 11:10:04 AM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I’m worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

I live in an apartment and I’m low income. A $15/mo increase is a big deal for me. Inflation has already increased my grocery bills and other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Taevon Reyna
247 SE 160th Ave Apt A207 Portland, OR 97233-3589
taylor.stephenson28@gmail.com

From: taylor.stephenson28@everyactioncustom.com on behalf of Taevon Reyna
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (31)
Date: Wednesday, May 24, 2023 11:10:21 AM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I’m worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Taevon Reyna
247 SE 160th Ave Apt A207 Portland, OR 97233-3589
taylor.stephenson28@gmail.com

From: billiard58@everyactioncustom.com on behalf of William Dodge
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (32)
Date: Wednesday, May 24, 2023 11:34:19 AM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This proposed increase will make it more difficult for me to pay bills. For a disabled person with a low, limited income like myself, being expected to pay more for electricity would be a hardship that is unjust and unfair during difficult times.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
William Dodge
5342 SE 17th Ave Portland, OR 97202-4812
billiard58@yahoo.com

From: random@everyactioncustom.com on behalf of Alezah Torell
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (33)
Date: Wednesday, May 24, 2023 12:01:33 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

I live in a house, and I'm low income, disabled, and a single parent. A $23 increase is a big deal for me. Inflation has already increased my grocery bills and other household expenses. No one should have to choose between electricity, mortgage, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Alezah Torell
7468 SE 50th Ave Portland, OR 97206-8373
random@zliberation.mozmail.com

From: will@everyactioncustom.com on behalf of Will Newman
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (34)
Date: Wednesday, May 24, 2023 2:12:41 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416).

I am on a limited income, and am unable to work, so little chance of increasing my income.

As a PGE customer, I'm worried about how a 16% rate increase will impact my household.

I have already done as much as I can to reduce my bill, including enrolling in the solar program and receiving energy assistance.

I am facing a $22.71 per month increase. Adding this much money to my electric bill will force me to choose between other household expenses.No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Will Newman
11124 S Bremer Rd Canby, OR 97013-6707
will@naturalharvest.us

From: tjzendlessobsessions@everyactioncustom.com on behalf of Travis Johnston
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (35)
Date: Thursday, May 25, 2023 1:38:04 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Travis Johnston
4707 SE Boardman Ave Apt 19 Portland, OR 97267-5937
tjzendlessobsessions@gmail.com

From: jorgs10@everyactioncustom.com on behalf of Michael Jorgensen
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (36)
Date: Wednesday, June 28, 2023 11:36:59 AM

[You don't often get email from jorgs10@everyactioncustom.com. Learn why this is important at https://aka.ms/LearnAboutSenderIdentification]

Dear Oregon Public Utility Commission,

I am writing for something different. If we really want to have a bigger impact on PGE and helping homeowners then we should be helping homeowners who qualify with going solar.

I work for Purelight Power; Oregon largest and highest rated Residential Solar Installer.

I want to offer homeowners free consultations on what have a personal solar system will do for homeowners that qualify.

Solar for homeowners allows them to take the money would have otherwise paid to PGE and instead pay it towards their monthly Solar bill. There is no money down; and the payments will be fixed. Plus, they now have the option to pay off their power bill. Help connect me to these homeowners so we can protect as many as we can from PGE's rising rates; but also the fact their house will pay PGE forever!

Sincerely,
Michael Jorgensen
4372 Coloma Dr SE Salem, OR 97302-5076
jorgs10@gmail.com

From: susanaddison@everyactioncustom.com on behalf of Susan Addison
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (37)
Date: Monday, June 5, 2023 10:39:07 AM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

I am a single mom and also struggling with a disability, so I do absolutely everything possible to keep my essential monthly bills low. This increase would be a hardship.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Susan Addison
3721 SE 35th Pl Portland, OR 97202-3367
susanaddison@hotmail.com

From: jduan318@everyactioncustom.com on behalf of Jon Duan
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (38)
Date: Saturday, May 27, 2023 9:30:09 AM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

Especially for my family, we have some elders living with us with no income. Any additional cost added will impact us our capacity to take good care of the elders.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Jon Duan
2115 NW Jessamine Way Portland, OR 97229-8549
jduan318@gmail.com

From: c7h3l0b8@everyactioncustom.com on behalf of Peter Hsi
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (39)
Date: Saturday, May 27, 2023 11:57:57 AM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

We've already cut our expenses to the minimum but my limited income does not cover our essential monthly bills -- utilities, home, and food. I've exhausted our savings, leaving nothing for contingincies. Specifically, though we have good inusurance, my house recently suffered storm damage that isn't 100% covered by insurance. I'm also paying off medical bills from 2 years ago, and still have additional untreated medical needs.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between utilties, housing, medical, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Peter Hsi
14625 SW Bonnie Brae St Beaverton, OR 97007-3614
c7h3l0b8@duck.com

From: jessicadinsmore@everyactioncustom.com on behalf of Jessica Dinsmore
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (40)
Date: Monday, May 29, 2023 9:13:04 AM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Jessica Dinsmore
1051 Oak St Silverton, OR 97381-1965
jessicadinsmore@icloud.com

From: ldmc44@everyactioncustom.com on behalf of Larry D McAulay
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (41)
Date: Tuesday, May 30, 2023 11:00:04 AM

Dear Oregon Public Utility Commission,

Sirs,
I am writing to comment on the PGE rate case (UE 416).
As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to my electric bill will force me to choose between other household expenses.
No one should have to choose between electricity, rent, medication, and food.

At a time of continued historic inflation, raising bills this much will have real impacts on low income Oregonians.

I urge the Commission to reduce this increase wherever possible.
Thank you for your consideration.

Sincerely,
Larry D McAulay
10045 SW 85th Ave Apt 16 Portland, OR 97223-8898
ldmc44@gmail.com

From: editxprs@everyactioncustom.com on behalf of Candace Stewart
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (42)
Date: Tuesday, May 30, 2023 4:57:54 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I’m worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food, and I definitely would have to do that, in spite of working daily to reduce my use of electricity as much as possible.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Candace Stewart
314 SE 15th Ave Portland, OR 97214-1415
editxprs@gmail.com

From: kskristy2002@everyactioncustom.com on behalf of Kristy Stephens
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (43)
Date: Thursday, June 1, 2023 7:23:29 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm appalled how a 16% rate increase for residential customers will impact my household.

I struggle to afford food after I pay for my mortgage and utilities. I don't go on vacations or buy nice things. I live very frugally. I save energy and turn off lights and conserve water constantly.

This would be the largest rate hike in 20 years and inflation, putting strain on middle class which in turn, devastates economies that is made up primarily of middle class.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Kristy Stephens
32137 S Shady Dell Rd Molalla, OR 97038-9484
kskristy2002@yahoo.com

From: cmichaelhalsey@everyactioncustom.com on behalf of Chad Halsey
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (44)
Date: Sunday, June 4, 2023 3:44:23 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Adding this much money to electric bills will force my family to choose between other household expenses. I'm on a limited income through SSI. I shouldn't have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Chad Halsey
4065 Market St NE # 21 Salem, OR 97301-1906
cmichaelhalsey@gmail.com

From: cadie.hennig@everyactioncustom.com on behalf of Candace Vessels
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (45)
Date: Thursday, August 3, 2023 1:49:43 AM

[You don't often get email from cadie.hennig@everyactioncustom.com. Learn why this is important at https://aka.ms/LearnAboutSenderIdentification]

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Candace Vessels
3215 SW Doschdale Dr Portland, OR 97239-1157
cadie.hennig@gmail.com

From: Natasha_vdn@everyactioncustom.com on behalf of Natalia Neal
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416
Date: Tuesday, May 23, 2023 4:24:39 PM

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Natalia Neal
17373 SE Forest Hill Dr Damascus, OR 97089-2751
Natasha_vdn@yahoo.com

From: cadie.hennig@everyactioncustom.com on behalf of Candace Vessels
To: PUC PUC.PublicComments * PUC
Subject: Public Comments on UE 416 (46)
Date: Thursday, August 3, 2023 1:49:54 AM

[You don't often get email from cadie.hennig@everyactioncustom.com. Learn why this is important at https://aka.ms/LearnAboutSenderIdentification]

Dear Oregon Public Utility Commission,

I am writing to comment on the PGE rate case (UE 416). As a PGE customer, I'm worried about how a 16% rate increase for residential customers will impact my household.

Single-family homes are facing a $22.71 per month increase. Multifamily homes are looking at a $15.81 monthly increase. Adding this much money to electric bills will force many families to choose between other household expenses. No one should have to choose between electricity, rent, medication, and food.

This would be the largest rate hike in 20 years, since the Western Power Crisis. At a time of continued historic inflation, raising bills this much will have real impacts on Oregonians.

I urge the Commission to reduce this increase wherever possible. Thank you for your consideration.

Sincerely,
Candace Vessels
3215 SW Doschdale Dr Portland, OR 97239-1157
cadie.hennig@gmail.com

From: Lois Foster
To: PUC PUC.PublicComments * PUC
Subject: rate hike
Date: Tuesday, May 23, 2023 6:25:22 PM

I am alarmed at the proposed rate hike from PGE. Even a "small" rate increase of 15 $ would impact my life in a very negative way. PGE doesn't need to increase rates on the backs of everyday seniors.

From: Rachel Watsky
To: PUC PUC.PublicComments * PUC
Subject: Rate increase
Date: Monday, June 19, 2023 5:15:02 PM

Hello,

I am extremely concerned about PGE's proposed rate increase. This is the second increase in a row and honestly I don't know how I'd be able to afford it. I, like many others, was laid off and am struggling to get by as is.

The lack of transparency on what "capital investments" our money would be going towards is concerning. Additionally, I'm having a hard time believing a company like PGE needs this money so badly. NW Natural has enough capital on hand to attack Eugene's ordinance with a costly campaign and lawsuit, why should we believe PGE is using their money appropriately? If they are to be a government sanctioned monopoly, where is the financial oversight?

I strongly oppose this rate hike.

Best,
Rachel Watsky

From:	Erin Coyne
To:	PUC PUC.PublicComments * PUC
Subject:	Rate increases
Date:	Saturday, June 17, 2023 9:21:28 PM

You don't often get email from erincoyne01@gmail.com. Learn why this is important

I am very opposed to this increase. It's too much when families are struggling to make ends meet. I'd understand 2%, 3%….. 14% could be DEVASTATING to some families who will have to choose between paying their electricity bill or buying groceries or gas for their car to get to work…. Please do not do this.

Erin Coyne

From: Marjorie Cameron
To: PUC PUC.PublicComments * PUC
Subject: Re: OREGON PUC RESPONSE: RE:
Date: Friday, May 26, 2023 5:57:04 PM
Attachments: image001.wmz
image003.png
image004.png
image003.png

Thanks for the response to my email regarding the increase in rates. It is PGE and I live in Beaverton. I am 78 years old and still have to work part time because of very high rent and all the other expenses due to the current inflation rates. Unfortunately I am low income making it even more hard for me to manage the forever ending increases.
Thank you,
Marjorie Cameron

On Fri, May 26, 2023, 12:22 PM PUC PUC.PublicComments * PUC <PUC.PUBLICCOMMENTS@puc.oregon.gov> wrote:

> Good afternoon,
>
> Thank you for taking the time to contact the Oregon Public Utility Commission with your comments in opposition to a pending rate increase request. The Commission currently has several open general rate cases. May I please have the name of the company your comments are intended for? This will ensure your comments are directed to the appropriate staff and docket.
>
> Thank you,
>
> *Deanna Rios*
>
> Senior Compliance Specialist (Lead)
>
> Hours: Tuesday-Friday 7:00-5:30
>
> Oregon Public Utility Commission
>
> Consumer Services Section
>
> Tel: 503.378.6600 Toll free: 1.800.522.2404
>
> deanna.rios@puc.oregon.gov

From: Marjorie Cameron <marjoriecameron1945@gmail.com>
Sent: Wednesday, May 24, 2023 9:27 AM
To: PUC PUC.PublicComments * PUC <puc.publiccomments@puc.oregon.gov>
Subject:

I am a 78 low income senior and because of the significant inflation I have to work weekends and that still isn't enough. A rate increase of $15.00 is a lot for me. Please don't raise rates on low income seniors.

Thank you,

M.Cameron

From: me wong
To: PUC PUC.PublicComments * PUC
Subject: Stand against Portland General Electric"s large rate increase
Date: Wednesday, May 24, 2023 9:22:27 PM

The 14% proposed rate increase is outrages! This large increase will burden many low-income elderlies that lives only on the small amount of Social Security check, and if inflation doesn't slow down by next year, it would create an even greater financial burden. Maybe PGE should decrease their CEO and upper management earnings and multi-million-dollar bonuses to fund a percentage of their projects and request for a smaller, affordable increase.

Thank you for listening to the concerns of the many "Voiceless" low-income elderlies!
They should not have to choose between using electricity or put food on the table.

From: melly belly
To: PUC PUC.PublicComments * PUC
Subject: The higher cost of energy
Date: Wednesday, May 31, 2023 11:03:59 AM

Dear Commissioners,

Hello,and thank you for this opportunity to comment on what will force further energy insecurity on me. I already barely use my energy in my home. Typically in the Winter, I layer up and there's no heat even when it snows. In the Summer, I try to use as little energy as possible. The hike that is being thought of for power will effectively have me trying to not use any power meaning most days I will be surrounded by walls and not using electricity except for a fridge that I cannot turn off. PGE's prices are high because it's a monopoly not because the new hike is necessary and Oregon should truly be looking for a public utility service that will compete with it. As stated this price hike in energy that is currently happening and the new one harms me currently and futuristically. Wages are not in line with needs and energy thanks to climate change that corporations have not done enough about, have left human beings to suffer the consequences and energy is now not a want but a need. The new hike treats energy like only the wealthy should have it and that means many people like myself and FAMILIES will have to figure out how to live without its use. I hope you will agree it's a great injustice coming out of the pandemic, heat domes, and freezing weather. People have died because they didn't have access to energy relief. Please save some lives and reconsider this decision to raise the energy bills in Oregon. Thank you again for your time on such an important matter at hand.

Sincerely,

Mel S.

--

“It’s not for you to call me resilient. It is for you to make sure that I don’t have to continue to be resilient under inhumane circumstances.”

From:	SILVIA TANNER
To:	PUC PUC.PublicComments * PUC
Cc:	Maria Dolores Torres; MOSER Nolan * PUC
Subject:	UE 416 - Comentarios de Maria Dolores
Date:	Wednesday, May 31, 2023 5:30:18 PM
Attachments:	Maria Dolores Testimonio Tarifas de PGE (1).pdf

(Español abajo)
Dear AHD Staff,

Please see attached the comments from Maria Dolores regarding PGE's proposed rate increase in Docket No. UE 416. I am helping Maria Dolores submit these comments. She is CC'd in this email.

Best,

Silvia

(English above)
Querido personal de AHD,

Por favor vean adjuntos los comentarios de Maria Dolores sobre la propuesta de incremento de tarifa de PGE en Docket No. UE 416. Estoy ayudándole a Maria Dolores a enviar estos comentarios. Ella está copiada en este correo.

Gracias,

Silvia

--
Silvia Tanner, JD *(pronouns she/her)*
Sr. Energy Policy and Legal Analyst

Office of Sustainability | Multnomah County

501 SE Hawthorne Blvd., Suite 600, Portland, OR 97214

T: 503.988.4092 | W: Office of Sustainability

From:	SILVIA TANNER
To:	PUC PUC.PublicComments * PUC
Cc:	Sushmita Poddar; MOSER Nolan * PUC
Subject:	UE 416 - Comments by Ms. Sushmita Poddar
Date:	Thursday, June 1, 2023 6:37:29 PM
Attachments:	20230523 - Sushmita Comments (1).pdf

Dear AHD staff,

Please see attached the comments by Ms. Sushmita Poddar for consideration in the PGE Rate Case, Docket No. UE 416. Ms. Poddar (CC'd) is a small business owner and community leader who keeps a really busy schedule and had not had an opportunity to finalize her comments until this evening. As a result, I am helping Ms. Poddar sent her comments just now.

We would appreciate your flexibility and consideration of Ms. Poddar's comments even though you asked to have comments in by May 31, 2023.

Thank you for your assistance.

Sincerely,

Silvia Tanner

--

Silvia Tanner, JD *(pronouns she/her)*
Sr. Energy Policy and Legal Analyst

Office of Sustainability | Multnomah County

501 SE Hawthorne Blvd., Suite 600, Portland, OR 97214

T: 503.988.4092 | W: Office of Sustainability

This email was encrypted for your privacy and security

From: Mary Bender
To: PUC PUC.PublicComments * PUC
Subject: UE 416 (1)
Date: Friday, May 26, 2023 2:07:47 PM

As a single family household on a fixed income, this increase of approximately $22 per month would highly impact our food budget! Choosing between good nutrition versus heating/cooling our home will be the outcome!
I understand PGE improvements were needed, but we just had an increase in electricity prices last year of roughly 13%!
We are doing our part to be wise and conserve by replacing an inefficient heat pump.
Please reconsider and or reallocate where the impact of increased costs occurs.

From: Marjorie Cameron
To: PUC PUC.PublicComments * PUC
Subject: UE 416
Date: Wednesday, May 24, 2023 9:27:30 AM

I am a 78 low income senior and because of the significant inflation I have to work weekends and that still isn't enough. A rate increase of $15.00 is a lot for me. Please don't raise rates on low income seniors.

Thank you,
M.Cameron

CASE: UE 416
WITNESS: Itayi Chipanera

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 3000

Redacted
Rebuttal Testimony
(Subject to Protective Order No. 23-039)

August 22, 2023

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

A. My name is Itayi Chipanera. I am a Senior Financial Analyst employed in the Accounting and Finance Section of the Rates, Safety and Utility Performance program of the Public Utility Commission of Oregon. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is found in Exhibit No. Staff/200 and my witness qualifications statement is provided in Exhibit No. Staff/201.

Q. What is the purpose of your testimony?

A. I am the revenue requirement summary analyst, and the purpose of my testimony is to present changes in revenue requirement associated with Staff's opening position. I also respond to the Company's Reply Testimony regarding insurance expenses and the state income tax flow through method proposed by AWEC.

Q. Did you prepare any exhibits for this docket?

A. No.

Q. How is your testimony organized?

A. My testimony is organized as follows:

REVENUE REQUIREMENT.

Q. Please discuss the overall changes to revenue requirement proposed in PGE's Reply Testimony.

A. PGE increased its revenue requirement request from $337.8 million to $346.5 million in its Reply Testimony.[1] The Reply Testimony revises the proposed revenue requirement to update power costs by an increase of $7.4 million and reduces base costs by an amount of $0.94 million. The components of the $346.5 increase can be disaggregated into roughly $116.4 million of power costs and $230.2 million of base costs. Staff summarized the updated revenue requirement as follows:

Table 1

	In Thousands (000's)		
	Initial Filing	**Reply**	**Requested Increase in Reply**
At Current Rates	$ 2,333,738	$ 2,333,738	
GRC Change for Reasonable Return on Equity (RROE)	$ 337,807	$ 340,107	$ 340,107
Subtotal	$ 2,671,545	$ 2,673,845	$ 340,107
Non-NVPC Adjustments		$ (940)	$ (940)
NVPC Adjustments		$ 7,364	$ 7,364
Total	$ 2,671,545	$ 2,680,268	$ 346,530
Overall Rate Increase	14.47%		14.85%

Q. What are the components of the $0.94 million reduction in base costs?

A. The components of the $0.94 million base cost adjustment are broken down in PGE Exhibit 1701 and consist of the revenue requirement impact of adding CO2 allowances to rate base and removing or reducing some expense

[1] PGE Exhibit 1701.

categories, as shown below.[2]

Table 2:	In Thousands (000's)
Item	Revenue Requirement Impact
CO2 allowances in rate base	$ 215
Memberships	$ (28)
Property Insurance	$ (338)
Transport Electrification Operation & Maintenance	$ (648)
Fleet Fuel Update	$ (140)
	$ (940)

Q. Have any of the issues discussed in your opening testimony been resolved?

A. Yes. In my opening testimony, I proposed reducing expenses to the apprenticeship training program in transmission and distribution by $108 thousand. That issue has been resolved through settlement with the Company.

Q. Has Staff resolved any other proposed adjustments to the Company's revenue requirement with PGE?

A. Yes. Staff has settled some issues involving both power costs and base costs. A few issues raised by Staff in Opening Testimony remain unresolved and specific Staff assigned to those topics are responding to PGE's Reply Testimony in each case. The table below shows the adjustments that have been settled with PGE for both Staff and Intervenors.

Q. Please summarize Staff's remaining unresolved adjustments to the Company's revenue requirement.

[2] Id.

A. Staff's unresolved adjustments are presented in the last segment of the tables presented below.

Unresolved Revenue Requirement Issues							
Rebuttal Testimony	**Issue No.**	**Staff**	**Proposed Staff Adjustments**	**Revenue**	**Expense**	**Rate Base**	**Staff Revenue Requirement Effect**
2900	COE	Muldoon	Cost of Equity @ 9.4%				(16,955)
3200	S-28	Young/ Stevens	Change from average of monthly averages to year end in rate base calculation	-	-	(169,819)	(15,249)
3300	S-12	Stevens	Vegetation Management	-	[redacted]	-	[redacted]
3500	S-9	Farrell	Uncollectible Accounts	-	(5,289)	-	(5,473)
3600	S-7	Jent	Wages & Salaries	-	-	(6,186)	(555)
4000	S-3	Ankum/ Fischer	CO2 Allowances	-	-	(3,021)	(271)
4000	S-3	Ankum/ Fischer	Fuel Stock (Major only)	-	-	(17,413)	(1,564)
Total of Unresolved Staff Proposed Adjustments				**-**	[redacted]	**(196,439)**	[redacted]

INTERVENOR ADJUSTMENTS - STATE INCOME TAX FLOWTHROUGH.

Q. What is the state income tax flowthrough proposal from AWEC?

A. AWEC is proposing that PGE transition to a flow-through method of accounting rather than the normalization method which PGE currently uses. In the proposal, accumulated deferred state income taxes (ADSIT), which has a current balance of $143 million, would be moved into a regulatory liability account, and the regulatory liability account would then be amortized over a two-year period for an annual amount of $71.5 million as a reduction of pre-tax expenses. The regulatory liability amortization of $71.5 million plus an additional removal of $2.7 million included as deferred income tax expenses in the Company's 2024 Test Year would then reduce the Company's overall Test Year expenses by an aggregate amount of $74.2 million.

Q. Please discuss Staff's position regarding the state income flowthrough proposed by AWEC.

A. AWEC's state income tax flowthrough proposal would in principle accelerate the return of accrued benefits back to customers over a two-year period. Accelerating the distribution of customer accrued benefits ultimately is unfair to customers as current customers get the full tax benefit for long-lived assets that future customers will continue to pay for. AWEC's proposal is unfair to customers across time, therefore Staff does not support this proposal.

Q. Is there an alternative where your concerns regarding the AWEC are somewhat alleviated?

A. Yes. If it is expected that the same amount would be flowed through to customers each year, then Staff could support the proposal. It is unclear to Staff that this “steady state” environment is applicable. In such a “steady state” environment, the intergenerational equity concern is addressed by each vintage of customers receiving the same benefit and there is no “last vintage” having to be the group disadvantaged.

INTERVENOR ADJUSTMENTS - PROPERTY INSURANCE.

Q. Please summarize AWEC's position related to property insurance (FERC Account 924).

A. Staff reviewed AWEC's Opening Testimony related to property insurance and notes that AWEC, "… recommend[s] using the known and measurable 2023 property insurance premiums…."[3] Additionally, AWEC noted that part of the increase related to 2024 included a project that was not involved in the current rate case, Clearwater Wind. [4]

Q. Did AWEC specify an adjustment for 2024?

A. Not in text form, but AWEC did reference confidential Exhibit AWEC/103, which Staff believes should be a reference to confidential Exhibit AWEC/203. In reviewing Exhibit AWEC/203 and PGE's Reply Testimony, Staff notes AWEC's recommended reduction for property insurance is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** related to Clearwater Wind.[5]

Q. Does Staff agree with AWEC's proposal to set the 2024 property insurance Expense at the 2023 level?

A. No. Simply put, insurance premiums generally increase for everyone every year and to generically request no increase seems untenable.

Q. What is Staff's position on this issue?

3 See AWEC/200, Mullins/16-17.
4 See AWEC/200, Mullins/16.
5 See PGE/1900, Batzler-Agnesse/2.

A. Staff proposes no adjustment to PGE's original 2024 request for expense for property insurance recorded in FERC Account 924 except related to Clearwater Wind noted below.

Q. What is Staff's position on the issue of removing Clearwater Wind from Property Insurance?

A. Staff agrees with AWEC on removing **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of property insurance related to Clearwater Wind.

Q. What is PGE's position on the issue of removing Clearwater Wind from property insurance?

A. PGE agreed with AWEC on removing **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of property insurance related to Clearwater Wind.[6]

Q. Does this conclude your testimony?

A. Yes.

---

[6] See PGE/1900, Batzler-Agnesse/2.

CASE: UE 416
WITNESS: Michelle Scala

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3100

REDACTED

REBUTTAL TESTIMONY
Energy Justice

August 22, 2023

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

A. My name is Michelle Scala. I am the Energy Justice Program Manager employed in the Strategy and Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is found in Exhibit Staff/600 and my Witness Qualification Statement is provided in Exhibit Staff/601.

Q. What is the purpose of this testimony?

A. This testimony responds to intervenor's Opening Testimony and the Company's Reply Testimony contained in Exhibit PGE/2600, Macfarlane-Pleasant, on Energy Justice in ratemaking and the Income Qualified Bill Discount (IQBD).

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

Exhibit Staff/3101........................Confidential Responses to Data Requests

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations in its Opening Testimony, identifying any adjustments you propose.

A. Staff made the following recommendations in its Opening Testimony:

Energy Justice in Ratemaking:

Staff strongly encouraged PGE to incorporate more intentional, observable, and measurable incorporations of energy justice into the Company's future rate proposals.

Staff continues to emphasize the importance of incorporating deliberate and substantial elements of energy justice within PGE's rate proposals.

Energy Justice in Rate Design:

Staff deferred to Exhibit 2000 Stevens for specific recommendations on PGE's proposed changes to rate design but encouraged parties to consider the inherent bias built into assumptions of homogeneity in the residential class, particularly regarding cost causation and cost allocation.

Customer Programs:

Staff recommended that PGE provide the Commission with a low-income needs assessment (LINA) that includes, but is not limited to, data on household demographics, energy burden, environmental justice metrics, and customer participation in assistance and energy assistance programs by customer segment to inform the next rate case and other proceedings.

Q. Does Staff provide additional details in this Rebuttal Testimony to recommendations made in its Opening Testimony?

A. Yes. Staff provides additional details about its recommendations for a low-income needs assessment (LINA), the Income-Qualified Bill Discount (IQBD) program discount level and tier structure, as well as the IQBD cost-recovery cap.

Q. Please summarize the additional details provided regarding Staff's recommendation to perform a LINA.

A. Staff maintains its recommendation on the LINA and has included additional terms discussed in greater detail within this exhibit. In summary, the terms Staff recommends for inclusion are:

- The LINA be completed no later than January 1, 2025.
- PGE is to work collaboratively with Staff and stakeholders to determine the parameters (scope and cost), objectives, and key deliverables for the LINA.
- The results and analysis of the LINA are to be made public to the level of granularity agreed upon between the utility, Staff and stakeholders; and PGE will host engagement with Staff and stakeholders to interpret the findings and inform HB 2475 programs, including but not limited to appropriate discount tiers and redesigns of applicable programs.
- The costs associated with the LINA be deferred through Docket No. UM 2219, the existing HB 2475 deferral[1] pending reauthorization and accrue at the modified blended treasury rate. Amortization of these costs

[1] *See* Docket No. UM 2219, *PGE Deferral of Energy Affordability Act Costs and Revenues*.

should be pursued expeditiously but subject to a prudence review absent an earnings test.[2] The application of an earnings test may be waived to the extent the Commission deems appropriate, subject to and consistent with the treatment of deferrals and automatic adjustment clauses (AAC) as discussed in Exhibit Staff/3700.

Q. Please summarize the additional detail provided to regarding Staff's recommendation on the Income-Qualified Bill Discount (IQBD) program.

A. Staff recommended in its Opening Testimony that PGE initiate a separate proceeding to implement a higher discount level into its Schedule 18 Income-Qualified Bill Discount (IQBD) program informed by community needs and engagement with the environmental justice community. In Staff Rebuttal Testimony, Staff has adjusted this recommendation to provide greater specificity relative to the discount level and tier structure Staff finds appropriate to implement at this time. The analysis behind this recommendation is discussed in greater detail later in testimony, but for the purposes of summarizing the key points, Staff recommends the following revised IQBD structure:

- Five tier State Median Income (SMI) structure:
    - Tier 0: 0-5%; Discount: <u>up to</u> 90%
    - Tier 1: 6-15%; Discount: <u>up to</u> 70%

[2] Staff would expect the costs of the LINA be eligible for full recovery within a reasonable forecast of costs discussed among parties during the joint parameter decision process.

- o Tier 2: 16-30%; Discount: 25%
- o Tier 3: 31-45%; Discount: 20%
- o Tier 4: 46-60%; Discount: 15%

- For Tiers 0 and 1; a sliding discount scale should be applied in decrements of 3.5 percent.
- For Tiers 2; 3; and 4; discounts will be a static percentage of bill across the income bracket.
- Staff further recommends that this revision come before the Commission as soon as practicable with changes reflected in the Schedule 18 tariff no later than the UE 416 rate effective date of January 1, 2024.

Q. Please summarize the additional details provided regarding Staff's recommendation for the IQBD cost-recovery cap.

A. In Opening Testimony, Staff also discussed the IQBD cost-recovery cap and recommended the cap be revisited at such a time that enrollment, costs, or other relevant metrics or design elements of the IQBD have changed to warrant an adjustment to this feature.[3] As a result of Staff's specific recommendations regarding the IQBD design and level of discounts, Staff believes that it is appropriate to adjust this feature in this rate proceeding. To this end, Staff is revising its recommendation to remove the Schedule 118 IQBD cost recovery cap of $1,000 per site in favor of a percentage of bill cap, effective with the new terms of the Schedule 18 IQBD program.

[3] Staff/600, Scala/44.

Q. Does other Staff testimony provide additional information or relate to the topics you discuss in this testimony?

A. Yes.

Automatic Adjustment Clauses:

Exhibit Staff/2200 Dlouhy-Muldoon-Scala-Stevens provided specific recommendations relative to automatic adjustment clauses and encouraged that future AAC requests include an inclusive discussion between parties that includes a holistic view of ongoing rate pressures on impacted customers. For the purposes of Rebuttal Testimony, Staff defers to Exhibit 3700 Dlouhy-Muldoon-Scala-Stevens.

Schedule 300 Customer Charges:

Exhibit Staff/2400 Nottingham-Shearer regarding proposed changes to Schedule 300 Customer Charges further recommended that PGE provide a study that assesses disparate impacts relative to pre-AR 653 reconnection charges and a discussion on alternative designs that are more responsive to equity for cost recovery associated with reconnection. For the purposes of Rebuttal Testimony, Staff defers to Exhibit 3900 Nottingham-Shearer.

ISSUE 2. ENERGY JUSTICE IN RATEMAKING

Q. Please summarize the main concerns raised by intervenors in this rate case regarding energy justice?

A. Intervenors speaking in the interest of energy justice raised several issues that, thematically, aligned with several of the concerns discussed by Staff in Exhibit Staff/600. Specific recommendations and proposed solutions to energy justice deficiencies in this rate proceeding were unique to each intervening organization. However, most arguments called for greater consideration to factors like recognition justice, procedural justice, and distributive justice in all matters of the case. Staff and intervenors also called for addressing issues of energy affordability for low-income customers and the need for a LINA to better understand energy burden in PGE's service territory. Specific intervenor arguments can be summarized as follows:

- Community Energy Project (CEP) recommended the consideration of energy justice in all aspects of the rate case, particularly advocating for low-income households and those affected by energy insecurity. CEP's specific points included a discussion of procedural justice, the impacts of the proposed rate increase on low-income households (and a recommendation for the Commission to reject said increase); introducing additional tiers to the IQBD with a steeper discount; consideration of 90 percent discount level; and expanded eligibility. Additionally, CEP recommended greater efficacy and exploration of energy efficiency and weatherization to reduce energy burden as well as an investigation into a bifurcated residential rate structure for qualified households that would cap the household energy burden at six percent; increasing IQBD discount levels, emphasizing energy efficiency, and addressing issues of procedural justice and equitable representation.

- The Community Action Partnership of Oregon (CAPO) similarly asserted that energy justice factors are not adequately considered in PGE's rate schedules, policies, and investments, and within the rate case proceeding. CAPO recommends rejecting PGE's proposed rate adjustments if energy justice factors are not more strongly considered. CAPO also suggests various factors for consideration, such as ensuring electricity availability without financial stress and giving more influence to customers with less power. In addition to pointing to the various dimensions of energy justice, CAPO recommends the Commission define and center the public interest in decision making; redesign residential rates to key household energy burden below six percent of household income and apply greater weight to a customers' ability to pay; and require accountability from PGE to stakeholder feedback across all regulated proceedings.
- Specific to energy justice considerations, residential customer advocate, the Citizens' Utility Board (CUB) proposed the elimination of the $1,000 per site cap on IQBD cost recovery per bill. CUB argues that removing this cap would decrease contributions of most customers and increase

contributions of the largest customers, thus avoiding an element of bypassability in the program. CUB also indicated that programs like the IQBD may need to be expanded to better reach the goal of lowering energy burden for the most vulnerable communities in PGE's service territory.

Q. How does PGE respond to concerns regarding energy justice raised by Staff, CEP, and CAPO?

A. PGE agrees that energy justice considerations can be integrated into the decision-making process but not as a replacement for cost causation principles. The Company indicated that it believes concerns related to distributive justice and procedural justice should be more appropriately addressed in a broader Commission-led investigation on energy justice in utility ratemaking. Specific to the IQBD, PGE affirmed previous indications that they would carve out a fourth tier, "Tier 0," to provide a 40 percent discount to qualified households earning 0 to 15 percent SMI.[4] This design would mirror the program currently in place for Northwest (NW) Natural Gas Company residential customers and represents an expansion from its current program which is comprised of three tiers and offers discounts ranging from 15 to 25 percent.

Q. Besides potential expansion of the IQBD program, is PGE proposing any changes that reflects Staff and intervenor concerns about the lack of energy justice principles in the rate case?

[4] PGE/2600, MacFarlane – Pleasant/11.

A. No. As summarized above, in PGE's Reply Testimony, the Company takes the position that concerns raised by Staff, CEP, and CAPO regarding distributive justice and procedural justice in Staff would be better suited in "a broader Commission-led investigation on energy justice in utility ratemaking."[5]

Q. Are there any items from the Company's Reply Testimony that Staff would like to address or correct?

A. Yes. While the Company's approach may appear agreeable at first glance, a closer examination reveals a strategic omission of crucial insights that underpin the core principles of energy justice and equitable rate design put forward by Staff. Staff's acknowledgement of the importance of cost causation principles in Opening Testimony should not be interpreted as saying that cost causation is superior to nor mutually exclusive from a process that includes energy justice principles. PGE's selective quotation from Staff's Opening Testimony misrepresents Staff's position by excluding the relevant context provided in the lines of text immediately thereafter:

> That said, cost-causal rates are informed by cost-of-service studies, which include assumptions and resulting cost allocations [that] are often a zero-sum process where lower costs for any one group of customers lead to higher costs for another group. Further still, as Justice William O. Douglas (1945) remarked, 'allocation of cost is not a matter for the slide rule. It involves judgement of a myriad of facts. It has no claim to an exact science.' Thus, it is crucial to recognize that cost causation is not the sole factor that should inform ratemaking nor is it an infallible determination of fair cost allocation.[6]

[5] PGE/2600 Macfarlane – Pleasant/9.
[6] Staff/600, Scala/16-17.

PGE's truncated reference minimizes the depth and resolve of Staff's position and the extent of our critiques regarding the current customer class structure and cost allocation methods. The omission perpetuates the siloed approach to energy justice, effectively sidestepping the systemic inequities that persist within the energy sector.

Q. Are there solutions to this issue Staff is prepared to put forward in this rate case?

A. Yes. As discussed in Opening Testimony, system benefits, ability to pay and/or manage risk, and social marginal cost models, are all examples of considerations that could inform equity driven evolutions to PGE's position and proposals. Unfortunately, the phrasing of Staff's Opening Testimony recommendation for the Company to "incorporate more intentional and tangible incorporations of energy justice into the Company's *future* (emphasis added) rate proposals" has seemingly given PGE the confidence to relegate these concepts as inappropriate for the current proceeding. PGE maintains this position despite the voluminous testimony on the pervasive and persistent social harms of reinforcing inequitable systems through inaction.

PGE's interpretation and failure to act in a timely manner in this docket may make it difficult to make as meaningful of changes as Staff had hoped. The confines present in the legal processes we follow limit the time left to debate and create authentic and actionable commitments by PGE. Staff is hopeful that an order in this docket can create those commitments or require PGE to engage in a separate proceeding that achieves the same result.

ISSUE 3. LOW INCOME NEEDS ASSESSMENT

Q. Please briefly describe PGE's position on conducting a LINA in its service territory.

A. PGE's Reply Testimony indicated that the Company is researching and considering the value and implications of working with a third-party contractor to conduct a low income needs assessment while also connecting with peer utilities who have already completed one.[7]

Q. Does Staff find this statement sufficiently addresses Staff and intervenors' requests for the Company to conduct a LINA?

A. No. Staff believes that PGE has intentionally postponed taking meaningful steps in pursuing a LINA for their service territory and may continue to do so absent specific Commission direction. Peer utilities that have independently pursued energy burden assessments did so nearly two years ago. This data has been used to inform engagement, HB 2475 program design[8] and other decision-making tables by the utilities, Staff, stakeholders and community. There has been unanimous support for the collection of this type of information and throughout UM 2211[9] engagement, interested parties have requested LINAs and more granular demographic information and environmental justice metrics to assess program efficacy and system inequities in PGE's service territory. PGE's response in Reply Testimony appears to continue to be an

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7 PGE/2600, Macfarlane – Pleasant/11.

8 *See* Docket No. 1410, *Avista Corporation's Advice No. 22-03-G Low-Income Rate Assistance Program; see also* Cascade Docket No. 1409, *Cascade Natural Gas Company's Advice No. 22-06-01 Arrearage Management Program*.

9 *See* Docket No. UM 2211, *Implementation of HB 2475*.

attempt to "placate" stakeholders and postpone meaningful analysis. Staff argues, that if the Company was truly considering and researching the use of a LINA, then at the very least, PGE's Reply Testimony would have included actionable information on what it has found thus far and what it would need to take action; at best the Company would have had one done months ago and used to inform this rate proceeding.

Q. Does Staff believe the Company should be required to conduct a LINA?

A. Yes. There is no reason to wait. Customers are in need now.

Q. Please explain.

A. The information provided through a LINA would serve to better inform how rates and programs can address these needs. Staff is concerned that the Company is putting off undertaking a LINA and continue to use its existing data, which Staff views as incomplete and possibly reflecting selection bias. For example, the data PGE receives through the Eligibility Data Sharing Agreement between Oregon Housing and Community Services and the Company includes **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[10] Yet, in spite of access to that data, PGE did not opt to analyze or incorporate this information its proposed IQBD revisions or a discussion of energy burden with interested parties.

[10] PGE's Confidential Response to OPUC DR 858, Attachment A.

Staff recommends the Commission directs the Company to complete a LINA and puts forward the following terms:

- The LINA be completed no later than January 1, 2025.
- PGE is to work collaboratively with Staff and stakeholders to determine the parameters (scope and cost), objectives, and key deliverables for the LINA.
- The results and analysis of the LINA are to be made public to the level of granularity agreed upon between the utility, Staff and stakeholders; and PGE will host engagement with Staff and stakeholders to interpret the findings and inform HB 2475 programs, including but not limited to appropriate discount tiers and redesigns of applicable programs.
- The costs associated with the LINA are to be deferred through the existing HB 2475 deferral pending reauthorization and accrue at the modified blended treasury rate. Amortization of these costs should be pursued expeditiously but subject to a prudence review. The application of an earnings test may be waived to the extent the Commission deems appropriate, subject to and consistent with the treatment of deferrals and AAC's as discussed in Exhibit Staff/3700.

ISSUE 4. INCOME-QUALIFIED BILL DISCOUNT PROGRAM

Q. Please briefly describe the current state of the IQBD available to PGE customers.

A. PGE's IQBD program currently offers residential customers earning at or less than 60 percent of the state median income (SMI) percentage of bill discounts ranging from 15-25 percent, depending on a customer' s household size, gross income, and medical certificate status. As of July 2023, just over 60,000 residential customers have enrolled in the IQBD program. PGE expects the program to grow to roughly 90,000 customers by year-end (2023), and to program maturity (approximately 75 percent of eligible customers or 120,000 customers) by the end of 2024.[11]

Q. Does PGE plan to expand the IQBD program?

A. Yes. As noted earlier in this Exhibit, PGE's Reply Testimony proposes to add a fourth tier (Tier 0) to the IQBD program, providing a 40 percent bill discount for households with incomes at or below 15 percent of the SMI, adjusted for household size. PGE estimates that approximately 20 percent of current and future IQBD participants will be eligible for the larger discount tier offered to households, which would increase direct program costs by about $3 million by 2024 to roughly **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[12]

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11 PGE/2600, Macfarlane – Pleasant/10.

12 Staff/3101, Scala/1, PGE's Confidential Response to CUB DR 085, Attachment A.

Q. Does Staff agree with PGE's IQBD proposal?

A. No. Staff believes that this proposal is insufficient to address known energy burden metrics within PGE's service territory based on available data, including but not limited to, Low Income Home Energy Assistance Program (LIHEAP) and Oregon Energy Assistance Program (OEAP) data, peer utility LINA energy burden statistics, American Community Survey income data (Census Bureau), and community feedback. Data from these sources evidence thousands of households in PGE's service territory earn less than five percent of the SMI. This translates to a gross income of less than $217.00 each month. Even when factoring in the available public assistance programs such as Supplemental Nutritional Assistance Program (SNAP), Temporary Assistance for Needy Families (TANF), LIHEAP, Section 8 housing vouchers, *in addition to* the Company's IQBD proposal, many of these households would still have an extremely high energy burden.

Q. What did the Company base its proposal on?

A. The Company's IQBD proposal appears to be based on aligning the program with the same four tier structure in place with its peer utility, NW Natural, of which PGE shares many customers. Staff would also note that PacifiCorp's bill assistance program offers a 40 percent discount as the deepest tier. That said, none of these three utilities based this 40 percent number on any actual analysis of energy burden for qualified households. As noted by the Company in Reply Testimony, "PGE has not yet analyzed the impacts of energy burden but will be assessing changes to calculated burdens."[13] Put another way, PGE's IQBD discounts (in both their original and proposed designs) are not based on any actual energy burden assessment of need nor any reasonably available proxy for need.

Q. Please describe how Staff developed an IQBD structure that it believes more sufficiently addresses energy burden in the absence of a LINA.

A. In an effort to better inform an IQBD structure based on actual need, Staff first looked at the Oregon regulated utilities that *have* implemented bill assistance programs informed by energy burden assessments (i.e. LINAs); namely, Avista Utilities (Avista) [14] and Cascade Natural Gas Company (Cascade).[15] In both assessments, the utilities found that to adequately address energy burden for households earning zero to five percent SMI, the deepest discount tier would have to be at least[16] 90 percent. Additionally, the assessments indicated that for households earning less than 40 percent SMI, appropriate discounts should be set between 70 and 25 percent, depending on the income tier. Above 40 to 45 percent SMI, the discount levels decrease to be consistent with or lower than PGE's equivalent top tier. Staff then endeavored to gauge energy burden needs within PGE's service territory by analyzing **[BEGIN CONFIDENTIAL]** [redacted]

[13] PGE/2600, Macfarlane – Pleasant/10.

[14] *See* Docket No. ADV 1410, *Avista Corporation's Advice No. 22-03-G Low-Income Rate Assistance Program*.

[15] *See* Docket No. ADV 1409, *Cascade Natural Gas Company's Advice No. 22-06-01 Arrearage Management Program*.

[16] Cascade's Schedule 36 Energy Discount provides a 95 percent discount for households earning between 0-15 percent SMI, *see* https://www.cngc.com/wp-content/uploads/PDFs/Rates-Tariffs/Oregon/2022/Schedule-36.pdf.

[redacted] **[END CONFIDENTIAL]**.[17] This analysis gave Staff the opportunity to see **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. It is also worth noting that because this data set was limited to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** participants, and that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** participation rates are notoriously low, one can assume that there are many households earning less than zero to five percent SMI that do not receive additional energy assistance. Staff expects it is highly probably that PGE households earning the same or similar percentage of SMI as Avista or Cascade households experience the same or similar energy burdens as the "energy burden" metric is simply a ratio of income to household energy costs. To this end, Staff believes its review of the available data has provided enough evidence to develop an informed discount structure that is responsive to and more sufficiently addresses energy burden.

Q. Please explain what Staff is proposing for the IQBD.

A. Staff recommends implementing a five-tier structure for the IQBD program with a sliding scale for the two deepest discount tiers. Specifically, Staff recommends the following revised IQBD structure:

- Five-Tier State Median Income (SMI) structure:

[17] Staff/3101, Scala/2, PGE's Confidential Response to OPUC DR 859, Attachment A.

- Tier 0: 0-5%; Discount: up to 90%
- Tier 1: 6-15%; Discount: up to 70%
- Tier 2: 16-30%; Discount: 25%
- Tier 3: 31-45%; Discount: 20%
- Tier 4: 46-60%; Discount: 15%

- For Tiers 0 and 1; a sliding discount scale should be applied in decrements of 3.5 percent.
- For Tiers 2; 3; and 4; discounts will be a static percentage of bill across the income bracket.

Table 1 provides an example of how the structure would be applied to a hypothetical monthly PGE bill of $150.00 across all eligible income tiers.

Table 1. OPUC Staff Proposed IQBD Discount Structure

TIER	SMI %	Benefit %	Bill BEFORE Discount	Discount	Bill AFTER Discount
0	0.0%	**90%**	$150	$ 135.00	$15.00
	1.0%	**87%**	$150	$ 129.75	$20.25
	2.0%	**83%**	$150	$ 124.50	$25.50
	3.0%	**80%**	$150	$ 119.25	$30.75
	4.0%	**76%**	$150	$ 114.00	$36.00
	5.0%	**73%**	$150	$ 108.75	$41.25
1	6.0%	**70%**	$150	$ 105.00	$45.00
	7.0%	**67%**	$150	$ 99.75	$50.25
	8.0%	**63%**	$150	$ 94.50	$55.50
	9.0%	**60%**	$150	$ 89.25	$60.75
	10%	**56%**	$150	$ 84.00	$66.00
	11%	**53%**	$150	$ 78.75	$71.25
	12%	**49%**	$150	$ 73.50	$76.50
	13%	**46%**	$150	$ 68.25	$81.75
	14%	**42%**	$150	$ 63.00	$87.00
	15%	**40%**	$150	$ 60.00	$90.00
2	16-30%	**25%**	$150	$ 37.50	$112.50
3	31-45%	**20%**	$150	$ 30.00	$120.00
4	46-60%	**15%**	$150	$ 22.50	$127.50

Staff further recommends that this revision come before the Commission as soon as practicable with changes reflected in the Schedule 18 tariff no later than the UE 416 rate effective date of January 1, 2024. This structure provides more substantial relief for low-income households and addresses energy burden more effectively.

Q. Why is Staff proposing a sliding discount scale for the top two tiers?

A. Staff's proposal smooths the discount transitions between income brackets by utilizing a linear scale within the two deepest discount tiers to effect three assumed benefits. Specifically, Staff believes the sliding scale:

- Reduces unintended programmatic inequities between income thresholds that would be present in a model that includes significant jumps between discount levels despite smaller incremental changes in income level.

- Affords a more strategic and equitable use of funds by ensuring the level of discount more closely aligns to reported income rather than applying a fixed percentage across a broad income range.
- More closely aligns the program with Staff's analysis of energy burden distribution across income tiers.

Q. Has Staff estimated how the costs of Staff's IQBD proposal differ from what PGE has put forward?

A. Staff approximated the costs of its proposal using two methodologies. In both methodologies, Staff based the enrollment distribution on IQBD and LIHEAP participant income data and assumes that 10 percent of participants would fall into Tier 0; seven percent in Tier 1; 32 percent in Tier 2; 25 percent in Tier 3; and 26 percent in Tier 4.

Q. What was the result of Staff's analysis using the first methodology?

A. The first approach integrated the additional tiers, averaging the discount for Tiers 0 and 1 (which would have the smoothed benefit curve in practice) into PGE's actual and forecasted monthly discount workbook provided in the Company's confidential response to UE 416 CUB DR 085, Attachment A.[18] Because Staff did not incorporate the smoothing in this model, the calculation provided a high and low approximation of adding the two tiers and additional discounts. On the high end, at 2024 year-end (120,000 enrolled), the program could reach roughly **[BEGIN CONFIDENTIAL]** [redacted] **[END**

[18] Staff/3101, Scala/1.

CONFIDENTIAL]; on the lower end, using this methodology, the program could reach approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. What was the result of Staff's analysis using the second methodology?

A. In Staff's second approximation, Staff assumed an average monthly bill of $150 across all participants, based on IQBD reported data, and applied the same 120,000 by 2024 year-end enrollment assumptions. Similar to the first methodology, Staff averaged the discount offered across the smoothed discount tiers, which effectively assumes equal distribution of participants across the intra-tier decrements. Using this methodology, Staff estimated that the program would cost roughly $62.3 million at maturity.

Table 2. Staff IQBD Proposal Cost Estimate

Program Maturity (20% ~120,000)			
SMI	**average discount**	**customers enrolled**	**discounts**
0-5%	$ 121.88	12,000	$ 1,462,500.00
6-15%	$ 81.60	8,680	$ 708,261.83
16-30%	$ 37.50	37,944	$ 1,422,918.44
31-45%	$ 30.00	29,884	$ 896,525.78
46-60%	$ 22.50	31,492	$ 708,561.81
		monthly	$ 5,198,767.87
		annual	**$62,385,214.43**

Staff notes that even as a range of potential costs across two separate methodologies, estimates could still show some variance above and below both the upper and lower bounds as the distribution of participants between tiers must be assumed to a certain degree and discount payments are averaged within the tier.

Q. Has Staff considered the impacts of its proposal on rates?

A. Yes. Staff is mindful that the additional program costs from the current structure will result in an increase to rates. That said, Staff would make two main points with regard to its consideration of this fact; that it is necessary to expand the IQBD program to function as intended and that consideration of rate impacts must happen holistically.

Q. Please explain why it is necessary to expand the IQBD program for it to function as intended?

A. There is no uncertainty that current IQBD discount levels *and* the proposed Tier 0, 40 percent discount, do not sufficiently reduce monthly energy costs for households and communities experiencing severe energy burden. Even Staff's proposal, which does not include adjusting discount levels for participants with 60 and 30 percent SMI, may not sufficiently mitigate energy burden for some households. To this end, some additional cost is inevitable if the Commission is to pursue rates and programs that address differential energy burdens as intended by the Energy Affordability Act (House Bill 2475). While it is a concern that an economic recession and rising unemployment may have significant implications on the potential enrollments and thereby costs of the program, reducing the efficacy of the IQBD now would essentially render it meaningless for Oregon's most vulnerable communities should those conditions transpire. To the extent that Staff is endeavoring to promote a design that serves characteristically energy burdened households, Staff believes an unexpected rise in IQBD costs attributable to economic or anomalous events is better addressed on a case-by-case basis (e.g. separate programs; deferral; public assistance) rather than to preemptively ration relief.

Q. Please explain why Staff advocates for a holistic consideration of rate impacts?

A. Staff concludes that consideration of rate impacts must happen holistically and with equity in mind. Low-income and other environmental justice communities are well evidenced as being disproportionately burdened by system costs and more vulnerable to energy insecurity. [19] Thus, under the current state, the Commission cannot adopt any rate increase to residential bills (and there are many in this proceeding) without disproportionately impacting those already facing higher energy burdens. That said, to the extent the associated cost of Staff's proposal operates in the interest of distributional justice and provides profoundly more needed relief than it draws on a per household basis, Staff would argue the change just and reasonable. Conversely, if the Commission were to adopt rate increases put forth in UE 416 that exclude meaningful action relative to energy burden, the results would undoubtedly exacerbate systemic inequities and energy insecurity.

Staff has worked to approximate the average dollar impact to rates for residential customers as a result of this design and finds that at maturity,

[19] In 2022, the Oregon Legislature passed HB 4077 which expanded the definition of "environmental justice communities" to broadly include communities of color, communities experiencing lower incomes, communities experiencing health inequities, tribal communities, rural communities, remote communities, coastal communities, communities with limited infrastructure and other communities traditionally underrepresented in public processes and adversely harmed by environmental and health hazards, including seniors, youth, and persons with disabilities.

assuming the $62.3 million figure, Schedule 7 customers would expect to see a roughly $2.30 increase to the current Schedule 118 customer charge, for a total of $3.44 per monthly bill. Non-residential customer charges will also increase, however Staff's proposal also includes revisions to the Schedule 118 terms that, if adopted, will impact the level of increase experienced by all customers (residential and non-residential).

Q. Is Staff saying that the increased costs of the IQBD necessitate changes to the current cost recovery mechanism?

A. Yes. Although, Staff believes changes to the IQBD cost recovery mechanism, Schedule 118, would be appropriate regardless of evolutions to the current discount structure.

Q. Please elaborate on why Staff believes the cap should be reconsidered.

A. Schedule 118 currently imposes a per site cap on cost recovery from non-residential customers of $1,000 or 877,193 kWh at the current budget given it functions as a volumetric charge. This cap effectively shifts significant costs of the program from larger non-residential customers on to all other customers. Staff finds it appropriate to revise this term to allow for a more equitable distribution of costs. Consistent with Staff's position in Opening Testimony that "the cap [should] be revisited at such a time that enrollment, costs, or other relevant metrics or design elements of the IQBD have changed to warrant an adjustment to this feature."[20] To the extent that Staff's proposal

[20] Staff/600, Scala/44.

has increased costs and altered design elements, Staff finds the adjustment warranted.

Q. Do Staff or other parties have recommendations on how to the Schedule 118 cap?

A. Yes. In Opening Testimony, CUB argued to remove the cap and alluded to its position that exclusion of such a feature should be consistently applied across all utility HB 2475 programs. Like Staff does here, CUB's Opening Testimony highlights how the cap shifts significant costs from larger customers to smaller customers, a problem exacerbated as the program matures and costs increase. CAPO similarly argues for larger customers to pay their fair share, although a specific proposal was not explicitly made.

Staff's recommendation is to remove the dollar cap and instead apply a percentage of bill cap. Staff believes this approach would mitigate larger customer concerns about significant shift in proportional costs between residential and non-residential customers while significantly improving the equitable distribution of costs between differently sized customers and reducing the rate impacts of program maturation and cost increases for the majority of customers. Based on current and forecasted costs associated with Staff's proposed IQBD design, Staff believes the Schedule 118 cap should be set at two percent of monthly billed amounts per site on all non-residential customers. The calculation of this percentage would only apply to the bill amount before the Schedule 118 charge is added. Staff would also note that this two percent value is not intended to be absolute. Changes to enrollment distributions and forecasted costs may warrant future revisions.

Q. How would this change impact Schedule 118 cost recovery bill impacts?

A. Assuming the cost for the IQBD were to increase to roughly $62 million by 2024 year-end and neither the two percent cap nor CUB's recommendation were adopted, the average percentage of bill paid by Schedule 7 customers using 795 kWh per month would be 2.29 percent. The impact to nonresidential customer schedules varies widely depending on customer usage as the charge for these schedules is volumetric rather than fixed. For example, assuming the two percentage of bill cap is adopted, Staff's analysis of large nonresidential customer billing data[21] for Schedules 83, 85, and 89 found that most customers would have an effective cap of $35.00 or less per bill while the maximum cap would be approximately $33,000. While at a glance these numbers may seem profoundly different, Staff notes that they are generally proportional percentage of bill amounts lending to the "fair share" and "ability to pay" arguments made by intervenors and others. Staff also notes that implementing Staff's percentage of bill cap may not monotonically increase non-residential bills. Some smaller customers may see a reduction in their Schedule 118 charge if their usage is low enough.

Q. Should the Commission be concerned with the $33,000 cap for some larger customers, does Staff have any suggestions on how this could be mitigated beyond lowering the percentage cap?

[21] Staff/3101, Scala/3, PGE's Confidential Response to OPUC DR 779, Attachment A.

A. Perhaps, but as noted, even this amount is still two percent of the impacted customer's bill; thus, proportionally, it seems less alarming. Further this dollar amount represents an extreme outlier as less than 0.5 percent of customers would actually see a cap of more than even $1,000. That said, while it is not Staff's preferred approach and is considered an inferior alternative because it does not align with "fair share" and "ability to pay" arguments in this docket, the Commission could consider a combination of a flat dollar cap and a percentage cap. Staff does not view this as necessary but would view it as preferrable to the existing $1,000 cap, assuming the dollar cap is set higher.

Q. How do these estimates compare to PGE's Reply Testimony IQBD proposal?

A. Using PGE's IQBD cost estimates[22] and billing determinant data[23] with the existing Schedule 118 cost recovery work papers[24] Staff estimates that adding a fourth IQBD tier and 40 percent discount for residential customers earning zero to 15 percent SMI would increase the residential customers Schedule 118 fixed charge by approximately $1.46 per bill, for a total monthly Schedule 118 charge of $2.60. Staff estimates that nonresidential customers would see a volumetric Schedule 118 charge of approximately $0.026 per kWh. Further, assuming the $1,000 per site cap remains in effect, the volumetric

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22 Staff/3101, Scala/1, PGE's Confidential Response to CUB DR 085 Attachment A.
23 Staff/3101, Scala/3, PGE's Confidential Response to OPUC DR 779 Attachment A.
24 See Docket No ADV 1447, *PGE Advice No. 22-32, Schedule 118 Income-Qualified Bill Discount Cost Recovery Mechanism Update*.

Schedule 118 charge would not apply to a nonresidential customer's usage above 384,993 kWhs.

Q. What is the significance of capping nonresidential Schedule 118 to two percent of monthly billed amounts per site?

A. As noted, there are distributional equity outcomes associated with this approach as it moderates the per site significance of Schedule 118 revenues as it impacts the customer. The existing $1,000 cap is problematic to the extent that 1) as previously described, it considerably limits the contributions of larger nonresidential customers to the detriment of smaller ones that then face higher proportional Schedule 118 costs; and 2) the dollar cap is static and thus growth in the IQBD program will further exacerbate cost recovery inequities. In addition to moderating the per site significance the two percent value, specifically, is intentionally set at less than the median and average residential customer level impact. In other words, most residential customers, and residential customers on average, will pay a higher proportional cost to Schedule 118 cost recovery that nonresidential customers. This ratio may be revisited in the future based on changes to IQBD costs as the program matures. However, at this time, Staff finds the nonresidential two percent cap strikes a reasonable balance between residential and nonresidential customer impacts.

Q. Does Staff have any additional dynamics for the Commission to consider in terms of the IQBD proposals?

A. Yes. The IQBD structure is best informed by the available data and the perspectives of those closest to the issue. UE 416 intervenors advocating in the interest of environmental justice have spoken directly to IQBD and the need for deeper discounts for severely energy burdened households and communities. Their presence in this proceeding is a direct result of HB 2475, which provided dedicated funding, specifically for environmental justice voices and perspectives to be heard and inform the Commission. The decisions made in this proceeding must include fair consideration of the points made else their presence be in vain. Staff finds the Company's election to carry on in Reply Testimony with a veneer of agreement on the importance of energy justice without evolving its position or perspective based on those principles unsettling.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: Michelle Scala

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3101

Confidential Exhibits in Support Of Rebuttal Testimony

Protected Information Subject to General Protective Order No. 23-039

August 22, 2023

REDACTED

PGE Response to CUB DR 085 Attachment A

is filed in electronic format

This Exhibit is Confidential and Subject to General Protective Order No. 23-039

REDACTED

PGE Response to OPUC DR 859 Attachment A

is filed in electronic format

This Exhibit is Confidential and Subject to General Protective Order No. 23-039

REDACTED

PGE Response to OPUC DR 779 Attachment A

is filed in electronic format

This Exhibit is Confidential and Subject to General Protective Order No. 23-039

CASE: UE 416
WITNESS: Bret Stevens and
Robert Young

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3200

Rebuttal Testimony
Rate Base Calculation

August 22, 2023

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

A. My name is Bret Stevens. I am a Senior Economist employed in the Rates, Safety, and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is found in Exhibit No. Staff/2000 and my witness qualifications statement is provided in Exhibit No. Staff/2001. I also submitted joint testimony in Exhibit No. Staff/800 and Staff/2200.

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

A. My name is Robert Young. I am Managing Director at Economists.com, a consulting firm located in Portland, Oregon. My business address in 7380 SW Kable Lane, Portland, Oregon 97224.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is found in Exhibit Nos. Staff/800 and Staff/2100. My witness qualifications statement is provided in Exhibit No. Staff/2101.

Q. What is the purpose of your testimony?

A. This testimony is to respond to issues raised in PGE/1700 by witnesses Greg Batzler and Jaki Ferchland concerning Staff's recommendation for calculation of PGE's rate base.

Q. Please summarize your Opening Testimony, Staff/800, in this Docket.

A. Our testimony highlights a disagreement between Staff and PGE regarding the appropriate method to calculate PGE's rate base to determine the return component of PGE's revenue requirement. Specifically, the dispute is between the "pre-test period snapshot" (PTPSS) method employed by PGE and the "average of monthly averages" method recommended by the Staff. Staff estimated the difference in revenue requirement between the two methods used to calculate rate base to be about $21.7 million annually. Because PGE refused to respond to Staff Discovery Request (DR) 819 and provide Staff with the data required to calculate rate base using the average of the monthly averages approach, Staff developed a close estimate of PGE's rate base using the average of the monthly averages approach.

Q. Have you revised your estimate of the revenue requirement impact of your adjustment?

A. Yes, we have. As we discuss below, the revenue requirement effect of our rate base adjustment is now ($15.7).

Q. Please provide a brief summary of your recommendation for how rate base should be calculated for the purpose of calculating required net operating income (NOI).[1]

A. As stated in Opening Testimony, Staff recommends using the average of monthly averages method of rate base calculation for the purpose of calculating required NOI. Particularly, for the Test Year ending on December 31, 2024, the average of monthly averages rate base is calculated using a 13-month average for the 2024 rate base amounts,

[1] Net operating income is the income after taxes that provides a return on equity the Commission finds is reasonable to compensate investors.

without new capital additions that cannot be included in accordance with ORS 757.255. This 13-month average is the sum of the monthly balances from December of 2023 through December of 2024, less one-half of each December balance, divided by 12.

Q. How did PGE calculate rate base in this rate case for the purpose of calculating required NOI?

A. PGE used what Staff refers to as the Pre-Test Period Snapshot (PTPSS) method. This method calculates PGE's rate base as of December 31, 2023.[2] However, PGE does treat capital additions in 2023 differently from all other capital additions. Instead of calculating the contribution to rate base directly before the January 1, 2024, rate effective date for these 2023 capital additions, PGE annualizes a depreciation amount and includes that within its December 31, 2023, rate base calculation. This effectively gives 2023 capital additions a full year of depreciation and accumulated depreciation as a reduction to rate base.[3]

Q. Please summarize the main arguments made by PGE in PGE/1700 concerning your modified proposal to calculate rate base.

A. The main arguments made by witnesses Batzler and Ferchland in PGE/1700 are the following:

[2] PGE/200, Batzler – Ferchland/25.
[3] PGE/1700, Batzler-Ferchland/17.

1. The method that Staff proposed to calculate PGE's rate base in this proceeding "has never been used by any utility in the state of Oregon and unlikely to have been used by any other state commission."[4]
2. "Staff's method mixes and matches year-end numbers with average numbers, resulting in a very inequitable and unbalanced view of PGE's rate base, which has no historical precedent nor reasonable logic behind it."[5]
3. "Staff's method uses PGE's filed year-end (i.e., 12/31/2023) amount for gross plant and then effectively adds another half year of accumulated depreciation using PGE's total filed depreciation expense, which they state is an approximation of average accumulated reserve over the test period (i.e., 1/1/2024 through 12/31/2024)."[6]
4. "Staff's proposal would violate tax normalization rules as defined in Internal Revenue Code, Section 168(i)(9). As we discuss in PGE Exhibit 200, normalization rules require consistency in the calculation of book depreciation expense, tax expense, accumulated book depreciation, and accumulated deferred income taxes."[7]
5. "Internal Revenue Code Section 168(f)(2) states that if a utility does not use a normalization method of accounting, the utility may not take advantage of the benefits of accelerated tax depreciation provided in

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[4] PGE/1700, Batzler-Ferchland/13.
[5] *Id.*
[6] *Id.*
[7] *Id*. at 18.

Section 168. PGE would be required to utilize book depreciation to calculate its income tax expense."[8]

Q. Do you agree with PGE's arguments that the method Staff used to calculate rate base has never been used?

A. No. Staff's recommendation to use an average of monthly rate base averages rather than a year-end total, which is used in PGE's PTSSP, is not new and has been the Oregon Commission's favored method to calculate rate base.[9] Staff has proposed a modified average-of-monthly averages approach to account for the prohibition on allowing utilities to recover costs of new plant scheduled to come on-line in during the Test Year, which is after the rate effective date, while still recognizing that the plant that is in PGE's rate base will depreciate in the Test Year.

A primary difference between the PGE and Staff proposal is that PGE's PTPSS method holds the January 1, 2024, rate base level static for ratemaking purposes through the Test Year, even though depreciation expense will in fact be accounted for by the Company throughout the Test Year, while the average-of-monthly averages method recognizes that the plant in PGE's rate base as of December 31, 2023, depreciates during the Test Year.

The Test Year is intended to be representative of the Company's normal operations. Staff opposes PGE's method because it does not recognize the

8 *Id.*
9 Staff/800, Stevens-Young/4-8.

depreciation that will take place in the Test Year. Allowing PGE to ignore Test Year depreciation and keep the rate base estimate static as of December 31, 2023, increases PGE's Test Year Revenue Requirement by approximately $15.7 million.

Q. What is Staff's response to PGE's argument that Staff's method inappropriately mixes average and year-end numbers an approximation of depreciation over the 2024 Test Period.

A. PGE's arguments are a red herring. PGE takes issue with Staff's assumptions regarding PGE's 2024 depreciation. However, whether Staff's assumptions regarding plant balances and depreciation amounts are correct is not determinative as to whether the Commission should establish PGE's revenue requirement based on the assumption that PGE's rate base will not depreciate during the 2024 Test Year. If the Commission agrees with Staff that PGE is not entitled to a revenue requirement that keeps PGE's rate base static as of December 31, 2023, the appropriate rate base can be calculated as part of PGE's compliance filing.[10]

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[10] Staff asked for the requisite information to calculate rate base using its average of monthly averages methodology. PGE refused to provide the information necessary for the calculation stating:

> [Staff DR 189] requests information that PGE has not prepared or forecast and that is not included within this proceeding. Specifically, using an average of averages for 2024 accumulated depreciation and accumulated deferred income taxes (ADIT), requires a monthly forecast of plant closings from January 1 through December 31, 2024, which PGE has not yet developed as PGE has based its current request on plant closings as of December 31, 2023.

Since Staff was not able to calculate this adjustment, we are approximated the result through a modified approach. This modified proposal was based on half of PGE's 2023 depreciation expense given in PGE/201 and Staff's proposed ROE of 9.4 percent.

Q. Do you agree with PGE's argument that Staff's hybrid approach to the rate base calculation violates IRS tax normalization rules and would require PGE to use book depreciation to calculate its income tax expense?

A. No. PGE did not provide any data, information, or table that shows our *actual* proposed methodology does not comply with IRS guidelines on income tax normalization. We believe that our proposed method does comply with IRS normalization rules and would not affect PGE income tax calculation. Staff's understanding of IRS tax normalization rules is that as long as the rate base calculation allows for a pro rata flow of tax benefits back to the customer and does not accelerate that flow, PGE's access to those benefits is not affected.

Q. PGE states that other utilities use the year-end plant balances method to calculate rate base,[11] do you agree with that statement?

A. We addressed the Commission's historic use of the average-of-monthly averages and PGE's more recent use of the year-end method in stipulated cases in our Opening Testimony. For reasons relied on by the Commission in cases dating back to the 1970s, we believe that all utilities should calculate rate base using Test Year plant calculates using average of the monthly averages. We note that in UG 461, Avista accepted a settlement proposal to calculate rate base using 2024 plant balances on an average of the monthly averages basis. Whether it is a settlement or not, we do not

[11] PGE/1700, Batzler – Ferchland/13-15.

believe that the average of monthly averages approach would have been supported by the parties if there was concern it was not lawful.

Q. PGE states that its use of year-end plant balances to calculate rate base is consistent with ORS 757.355.[12] Do you agree that PGE's method of calculating rate base in this Docket is consistent with ORS 757.355?

A. Yes. Staff's proposed method of calculation is also consistent with ORS 757.355.

Q. Do you agree with PGE's assertion that adopting Staff's proposed rate base calculation methodology would cause PGE to under-collect on its rate base?[13]

A. No. Staff argues that using the average of monthly averages rate base calculation more accurately reflects the value of PGE's rate base in the Test Year, while still adhering to Ballot Measure 9. PGE's method over collects because rates are set based on a rate base value that is appreciably greater than the actual average rate base value during the test period. Staff does not believe we need a "make-up" call to counter the effects of ORS 757.355.

Q. By how much does Staff believe PGE's rate base calculation leads PGE to over collect?

[12] *Id.* at 16.
[13] *Id.* at 20.

A. Since PGE is not taking into account the vast majority of the depreciation that occurs during the Test Year when calculating its rate base, one can think of its calculated net income as being effectively based off of a higher ROE than the Commission approves. Given Staff's estimated rate base adjustment and corresponding revenue requirement adjustment, Staff argues that PGE's PTPSS methodology is leading PGE to over recover by roughly 36 basis points above the Commission's approved ROE.[14] This means that even if the Commission adopted the Staff recommend 9.4 percent ROE, PGE would effectively have "authorized" rates set to earn 9.76 percent ROE. Staff again notes that this calculation is based off Staff's best estimate of the effect of switching to the average of monthly averages.

Q. Does PGE's current methodology account for any depreciation in the test period?

A. Yes. As PGE notes in its Reply Testimony, PGE treats 2023 capital additions different from all preceding capital additions. As stated above, PGE annualizes a depreciation amount and includes that within its December 31, 2023, rate base calculation for all 2023 capital additions. This effectively gives all 2023 capital additions 12 months' worth of depreciation. One could conceptualize this methodology as depreciating a plant that comes online in March of 2023 through March of 2024.

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[14] This figure was calculated by dividing Staff's proposed net income including adjustments for settled issues and Staff's proposed ROE of 9.4 percent in opening testimony, by Staff's estimated adjusted rate base.

Q. Would the average of monthly averages approach proposed by Staff treat these 2023 capital additions the same as PGE's current PTPSS method?

A. No. For 2023 capital additions, Staff's approach would apply depreciation from the plant's online date throughout 2023 and apply half of the depreciation in 2024.

Q. Would the average of monthly averages approach always depreciate 2023 capital additions more than PGE's PTPSS method?

A. No. Since PGE is applying a full year of depreciation for 2023 capital additions, capital additions that come online in the latter half of 2023 will be valued less under PGE's approach than in Staff's approach, while capital additions that come online in the first half of 2023 will be valued higher than in Staff's approach. One way to think of this approach is that PGE underearns the first half of the year and over earns the second half of the year, and on average, earns the authorized rate of return on equity. Staff asserts that the average value of these capital additions over the course of the Test Year is a more theoretically sound metric than PGE's current annualization approach as it creates inconsistencies in how plant is valued based on when it comes online.

Q. Does Staff then want PGE to only apply the average of monthly averages methodology to 2023 capital additions?

A. No. Staff again asserts that this method is not only more theoretically sound for 2023 capital additions, but for PGE's entire rate base.

Q. What is Staff's recommendation to the Commission?

A. Staff recommends that the Commission order PGE to adopt the average of the monthly averages methodology that Staff proposed in Opening Testimony.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: Bret Stevens and Robert Young

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3201

Non-Confidential Response to Staff Data Request

August 22, 2023

OPUC Data Request 888

Regarding the worksheet "Rev Req Summary Check" in the Excel File 2024 "Unbundled ROO.xlsx" – please provide PGE's regulated return on equity and total rate base values on January 1, 2024, and December 31, 2024, assuming that a new plant is brought into service at a particular date. Please also provide the monthly rate base vales from the in-service date to December 31, 2023. For this example, assume the new the new plant cost $100 million and has a 10-year depreciable life. Please calculate these figures assuming the plant comes into service on each of the following dates: Please explain why this is the appropriate rate base amount from a conceptual viewpoint.

1. December 31, 2022,
2. January 1, 2023,
3. September 30, 2023,
4. December 31, 2023.

For this example, please use the following assumptions:

a) A 9.5% ROE,
b) This plant is the only investment in PGE's rate base,
c) Rates are set on January 1, 2024.

Please calculate these figures consistent with PGE's ratemaking methodology as used in UE 416 using the "Rev Req Summary Check" worksheet. For each of these in-service dates, please also provide a narrative explanation as to how this capital addition was included in the rate base calculation. If the PGE is unable to perform the calculation requested above, please still provide the narrative explanation as to how a capital addition put in service at each of the listed dates would be calculated for rate base purposes.

PGE Response to OPUC Data Request 888

PGE objects to this request on the basis of ambiguity and lack of clarity. Notwithstanding its objection, PGE responds as follows:

The file referenced by Staff provides a forecasted test year results of operations that is based upon a set of forecasted costs and assumptions. In particular, the revenue requirement determined involves an iterative calculation, which in part, calculates the revenues necessary to earn a specified return. As such, the return on equity (ROE) does not change, as it is a target amount. Additionally, the revenue requirement and rate base value for the four different in-service dates Staff provides above would all result in the same amount within the file referenced by Staff.

PGE also notes that Staff's example is not reflective of PGE's actual operations, in which PGE closes new amounts to plant every month, regardless of general rate case timing and thus, as we have demonstrated in previous filings is subject to regulatory lag that typically results in PGE having a greater amount of net investment on our books and serving customers then net plant investment used to set customer prices.

Attachment 888-A provides a revenue requirement for a $100 million investment, with a depreciable life of 10-years and a January 1, 2024 price effective date, assuming PGE's filed revenue sensitive amounts, with the exception of a 9.5% ROE (as requested by Staff) in place of PGE's requested 9.8%. The second tab of Attachment 888-A provides actual net plant amounts on a monthly basis using Staff's above assumed dates, plus January 1, 2024 and December 31, 2024.

CASE: UE 416
WITNESS: Bret Stevens

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3300

Rebuttal Testimony
Routine Vegetation Management
Marginal Cost Study, Rate Spread, and
Rate Design

August 22, 2023

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

A. My name is Bret Stevens. I am a Senior Economist employed in the Rates, Safety, and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is found in Exhibit No. Staff/2000 and my witness qualification is provided in Exhibit No. Staff/2001. I also submitted joint testimony in Exhibit No. Staff/800 and Staff/2200.

Q. What is the purpose of your testimony?

A. I discuss and review several issues in Portland General Electric's (PGE) general rate case. This includes PGE's budget and accounting for routine vegetation management, marginal cost study and rate spread, and rate design.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits in support of this testimony:

Exhibit 4001 .... PGE's Vegetation Citations and Proposed Thresholds
Exhibit 4002 .... PGE Audit Report E22-62

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. ROUTINE VEGETATION MANAGEMENT

Q. Please summarize your positions on Routine Vegetation Management issues from opening testimony.

A. Staff put forward four primary recommendations regarding routine vegetation management (RVM) in opening testimony.

1. A balancing account be created to track routine vegetation management costs.
2. An RVM Performance Based Ratemaking (PBR) mechanism be put in place to incentivize consistent vegetation management performance.
3. A system performance PBR mechanism be established to incentivize consistent service quality and network resilience.
4. A managerial disallowance of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for annual RVM costs for imprudent cost management.

Q. Did any interveners make proposals regarding routine vegetation management?

A. Yes. The Alliance of Western Energy Consumers (AWEC) submitted testimony on this subject as well. AWEC stated that PGE had not provided sufficient evidence to justify an increase in its RVM budget. As such, AWEC proposed that the budget not be increased.

Q. Briefly summarize how PGE responded to both Staff and AWEC's proposals in its Reply Testimony.

A. PGE did not agree with AWEC and claimed that it had submitted sufficient evidence to justify the budget increase.[1] The Company also discussed the drivers behind the cost increase and argued that hiring in-house crews would be more expensive.[2] PGE agreed with Staff's proposal to create a balancing account, although the Company states that it wants clear documentation of PGE's RVM budget in base rates.[3] However, PGE disagreed with Staff's proposal for a PBR mechanism to incentivize consistent vegetation management performance.

PGE claimed that a PBR mechanism is not appropriate for a handful of reasons. First, PGE claims that its vegetation violations have not recently increased so there is no need for the mechanism as RVM funds are already "well spent".[4] Second, PGE claims that both the metrics suggested, OPUC Staff Vegetation Violations, as well as the suggested thresholds are not appropriate. PGE states that because the thresholds proposed were the same thresholds used for PacifiCorp's they are not appropriate.[5] PGE also claims that Staff does not have any standardized internal policies on how to identify violations or log audit hours and that violations are an inappropriate metric for a PBR mechanism.[6]

1 PGE/2200, Bekkedahl-Putnam/21-22.
2 PGE/2200, Bekkedahl-Putnam/9-13.
3 PGE/2200, Bekkedahl-Putnam/14-15.
4 PGE/2200, Bekkedahl-Putnam/16-17.
5 PGE/2200, Bekkedahl-Putnam/17-19.
6 PGE/2200, Bekkedahl-Putnam/20.

PGE also disagreed with Staff's proposal for a PBR mechanism to incentivize consistent service quality and network resilience through service quality metrics (SQM). PGE claims that the prudence of its distribution investments should be evaluated on a case-by-case basis in a rate case instead of through a holistic PBR.[7] For both Staff's vegetation management PBR and service quality PBR mechanisms, PGE also claims that Staff has no legal right to impose a PBR. PGE also claims that Staff's proposed PBR mechanisms were unfair as they were purely "punitive".[8]

Lastly, PGE disagreed with Staff's proposed managerial disallowance of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. PGE claims that the cost drivers leading to the unprecedented increase in its RVM budget are largely out of its control. PGE described the increase in demand for vegetation management crews across the West, competing with high wages in California, and an increase in need of vegetation management crews because of extreme weather. PGE claimed that it has tried to retain local crews by offering more flexible schedules and year-round work. PGE also implied that Staff should propose recommendations for lowering PGE's RVM costs if Staff believes that costs were mismanaged.

Q. Has Staff's position on any of its opening testimony recommendations changed?

[7] PGE/2200, Bekkedahl-Putnam/28-29.
[8] PGE/2200, Bekkedahl-Putnam/19.

A. Yes. At this point, Staff is only asking the Commission to consider the Routine Vegetation Management proposal. However, Staff plans to continue to work on a Service Quality based Performance Based Ratemaking mechanism for future consideration by the Commission.

Q. How does Staff respond to AWEC's proposal?

A. Staff does not agree with AWEC. While this is an extreme increase in costs, Staff does recognize that the labor market for vegetation management services is tight – leading to increased costs. While PGE's method for calculating its budget is somewhat crude given that contract rates are still being negotiated, Staff believes that the proposed balancing account will be able to capture any discrepancies in labor pricing. Therefore, the balancing account should address AWEC's concern somewhat. Further, any overspend in the budget will be subject to prudence review by Staff.

Q. How does Staff respond to PGE's comments on the proposed RVM balancing account?

A. Staff agrees that there should be a clear documentation of PGE's RVM budget in base rates. Staff agrees that this amount should be the amount requested in PGE's opening testimony – **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. PGE suggests that there should be no performance standards associated with its routine vegetation management. What is Staff's position with that issue?

A. Staff continues to support, particularly with the extreme increase in cost, the creation of incentives for effective program management. Ratepayers pay for quality service. If the quality of service provided by PGE sufficiently degrades, customers should not be left paying the same amount for an inferior product. Staff posits that this price decrease should not be subject to regulatory lag and that the definition of “quality service” should be clearly defined. A PBR mechanism for vegetation management achieves these goals. With a PBR, no matter the performance of the Company, the expectations for service quality are clearly defined and commensurate reductions in price are clearly communicated. Since PGE is charged with spending the money allocated to the activity in rates in the most effective way possible while attaining compliance observations of violations, as recorded in Staff’s annual vegetation audits, should be extremely rare occurrences. If PGE achieves compliance with OAR 860-024-0016, the Company would not feel any financial impact from the proposed PBR.

Q. Does Staff agree with PGE’s assertion that a degradation in performance is a prerequisite for a PBR mechanism?

A. No. As stated in Staff’s opening testimony, Staff believes that a PBR focused on vegetation violations will act as a quick and efficient way of incentivizing PGE to improve its performance in the instance that it declines.[9] Staff strongly rejects the notion that a degradation in performance is necessary to clearly communicate standards and consequences. It is simply sound ratemaking.

[9] Staff/2000, Stevens/25.

Q. Does Staff agree with PGE's assertion that the thresholds in Staff's proposed RVM PBR mechanisms are imperfect?

A. Yes. As stated in Staff's opening testimony, the thresholds proposed were meant to be a starting point for a dialogue with PGE and intervenors about the appropriate thresholds.[10]

Q. What was the main theme of PGE's response to Staff's Opening Testimony on this issue?

A. PGE described how its system has different vegetation characteristics than PacifiCorp. While this implies that PGE believes that its thresholds should be higher than those in place for PacifiCorp, PGE offered no suggestion on alternative thresholds. Staff also notes that PGE's service territory is both smaller in terms of line miles and much more urban compared to PacifiCorp's, as such, not all of the characteristics of PGE's service territory point to higher thresholds.

Q. How does Staff respond to PGE's characterization of the proposed RVM PBR mechanism thresholds?

A. While Staff believes that a PBR mechanism is appropriate for incentivizing quality service and clearly communicating standards, Staff also recognizes that there is no perfect set of thresholds. Particular thresholds could be debated ad nauseam. Staff believes that any thresholds set for a PBR mechanism should have feedback from multiple parties and be periodically reevaluated - as was done with PacifiCorp in UE 399. Staff concedes that a better starting point

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[10] Staff/2000, Stevens/24 at 11-13.

would have been the thresholds proposed in UE 394.[11] Staff challenges PGE to explain why the concept of a RVM PBR mechanism is unfounded, given Staff's reasoning above; and, if PGE takes issue with Staff's proposed thresholds, Staff requests PGE to propose its own so that reasonableness of PGE's thresholds can be assessed.

Q. Does Staff agree with PGE's characterization of OPUC Safety Staff's vegetation audits?

A. No. It appears that PGE misunderstands or mischaracterizes the goal of the OPUC annual vegetation audit and the role OPUC Safety Staff perform.

Q. What is the purpose of the OPUC Safety Staff system-wide vegetation audits?

A. OPUC Safety Staff annually evaluate the compliance of the regulated utilities as it relates to vegetation clearances. OAR 860-024-0016 requires a minimum three feet of clearance for voltages normally used to distribute power, should the tree be considered "climbable" five feet of clearance is required. The OAR recognizes that vegetation intrusion may occur, but does not allow vegetation to come closer than six inches to the conductor under reasonably anticipated operational conditions. Thus, *at minimum* six inches should be smallest clearance ever seen throughout the service territory. Staff's audit process collects evidence of burned vegetation in the vicinity of conductors, which is an indication that contact has occurred. This evidence demonstrates that not only was either 3 or 5 feet not achieved, depending on whether the tree was

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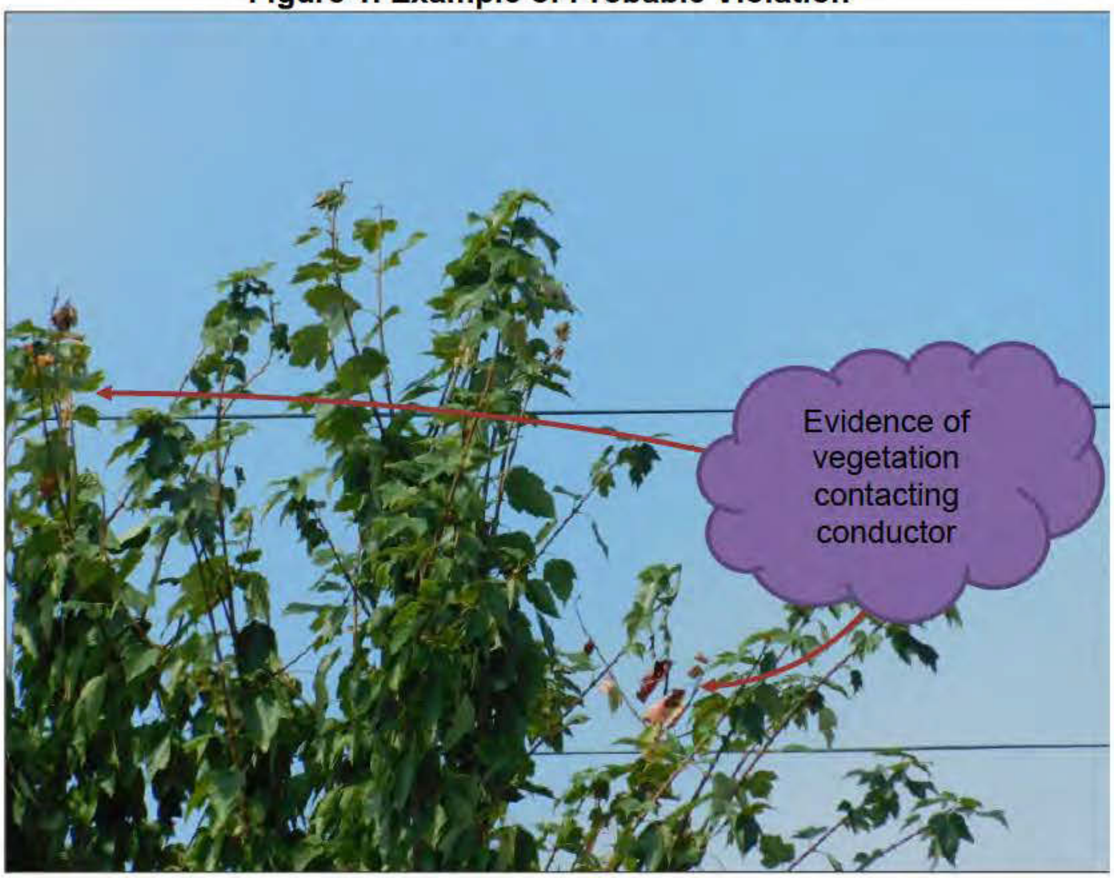
[11] UE 394, Staff/600, Dlouhy/28-32.

considered climbable, six inches was also not achieved. Staff reports them as probable violations and affords the utility 30 days to dispute them as probable. If the time elapses and the probable violation is not disputed by the utility, then they are considered violations. Shown below in Figure 1, is an example of a "probable violation".

Figure 1. Example of Probable Violation



Q. In its Reply Testimony, PGE inferred that there was no rigor or process involved in OPUC Safety Staff's audit process. How do you respond to this perception?

A. As a starting point, PGE seems to mischaracterize OPUC's data request responses. Staff responded that it uses its substantial history of audits, trained staff, and ever-advancing tools to perform its work. Staff documents every observation of contact, provides photographic support, and over the last years has also included geolocation so that there is absolute certainty that PGE is able to locate the infraction. Further, PGE used the characterization of "spot checking," which mischaracterizes the data request response provided by Staff.[12] Specifically, OPUC evaluates the system-wide performance of PGE's vegetation program and, except for areas which may be inaccessible for a variety of reasons, completes a system-wide analysis of the program. Because the indicator of contact is burned foliage, binoculars and trained eyes are the appropriate tools for the job. Nonetheless, if Staff were just wandering around the service territory it would seem that additional rigor would have only increased the number of violations found during the audit. This further demonstrates the ineffectiveness of PGE's Routine Vegetation Management (RVM) program as it is delivered today. Finally, to bolster an understanding of the rich content provided to support Safety Staff assertions, attached is the most recent audit report, E22-62, Exhibit 3301.

Q. Why does PGE dispute the validity of the OPUC annual vegetation audit?

A. Staff is perplexed by this characterization considering the program's long history. Perhaps just as PGE has misunderstood the goal of the audit, PGE may also perceive Staff's function with the audit incorrectly. The audit is intended to detect obvious non-compliance with the code. Staff's function is *not* to quality control PGE's contractor nor to identify patterns to modify PGE's

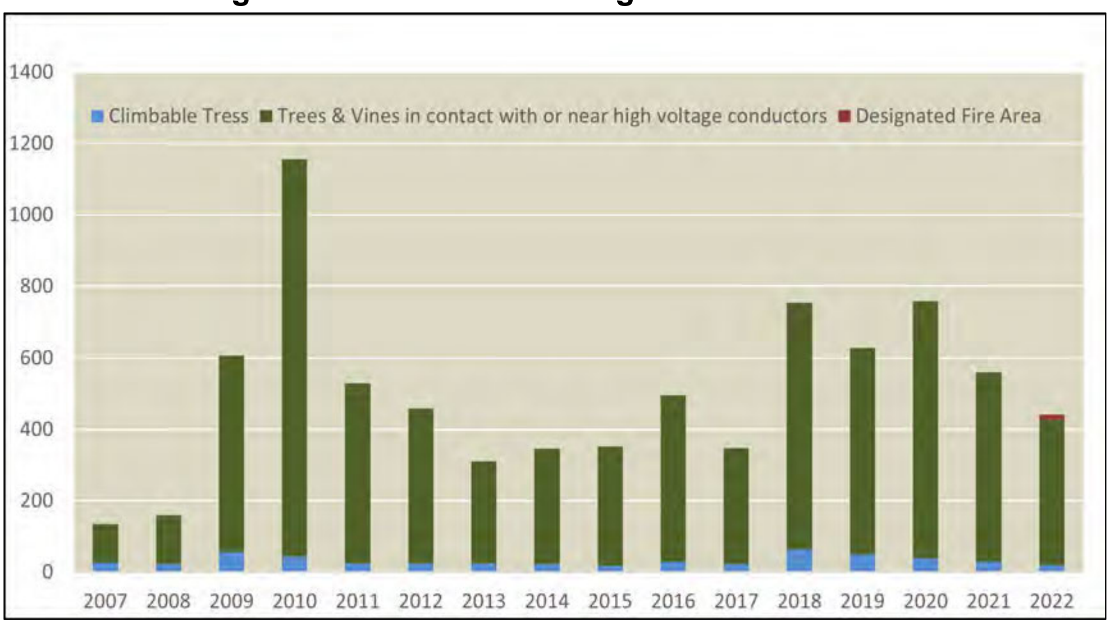
[12] See PGE DR 28.

program. That is the responsibility of PGE. As a result, any kind of correlation between where the audit is performed and how recently the vegetation has been trimmed is irrelevant and not valuable for the work Staff is performing.

Q. What is PGE's history with maintaining its system in compliance with vegetation regulations?

A. OAR 860-024-0016 has been in place since 2007. The history of PGE's compliance to the regulations relating to vegetation are shown below in Figure 2.[13] It is important to recognize that the annual safety audit is only a snapshot in time, but regardless, PGE's results seem to indicate it consistently fails to deliver a compliant vegetation environment. In UE 394 testimony, PGE pointed to a variety of reasons that violations could occur, but this rationale does not explain PGE's substantial deviation from a compliant system.

Figure 2. PGE Historical Vegetation Violations



[13] Note that designated fire areas have only existed since 2021 and have only been audit once – in 2022.

Staff is interested in ensuring that PGE delivers compliance, reliability, and safety and believes setting performance thresholds for violations is a beginning point, particularly with the substantial increase in budgets proposed by the Company. Staff is not interested in causing any delays in implementing these important programs, but it is interested in developing rigor in assessing the effectiveness of the spend. Regardless of PGE's history of compliance, Staff continues to contend that a RVM PBR mechanism is a sound method of communicating expectations and consequences and allows rate payers to pay for the performance they receive with minimal regulatory lag.

Q. How do you respond to PGE's comments regarding Staff's proposed Service Quality Mechanism based distribution PBR mechanism?

A. Staff's general philosophy on this topic is similar to what is described above. Staff contends that rates are set assuming quality performance. If service quality diminishes, customers should pay less for service because they are receiving an inferior product. The standards should be clearly communicated and the change in price should be subject to minimal regulatory lag. PGE instead contends that instead of the quality of its service being judged on a holistic level, that all distribution investments and decisions should be evaluated on a case-by-case basis.[14] Staff strongly disagrees with this sentiment. A resilient system does not come from a series of myopic decisions, but instead from comprehensive long-term planning. As such, it is

[14] PGE/2200, Bekkedahl-Putnam/19.

appropriate to judge the quality of planning by the performance of the system as a whole.

Q. How do you respond to PGE's claim that allowing the Commission to decide how to use funds placed in a deferral by the SQM based distribution PBR mechanism expands the Commission's authority?

A. All legal questions will be addressed in Staff's opening brief.

Q. PGE states in its Reply Testimony that imposing an SQM based distribution PBR mechanism will "undermine efforts in the Distribution System Planning process."[15] Do you agree?

A. No. PGE does not substantiate this claim in its testimony.

Q. How do you respond to PGE's claim that the Commission would not legally be able to impose either of Staff's proposed PBR mechanisms?

A. Similar to the question of expanding Commission authority, this is a legal question which will be addressed in Staff's opening brief.

Q. Is Staff still proposing both PBRs?

A. No. As stated above, Staff is only asking the Commission to consider the proposed PBR for Routine Vegetation Management. Staff plans to continue to work on an SQM based PBR mechanism for later adoption by the Commission.

Q. PGE objected to application of PacifiCorp's performance targets being applied to its system. How do you respond to the criticism?

A. Staff provided those targets as a starting point for discussion, however found no useful information in PGE's Reply Testimony to modify its position. As a

[15] PGE/2200, Bekkedahl-Putnam/29 at Lines 4-7.

comparison, PGE has approximately 7,775 miles of non-HRFZ overhead facilities, while PacifiCorp has about 12,000 miles, which makes it challenging to contemplate a higher threshold. However, Staff again reviewed the basis for the PacifiCorp targets in UE 399. PacifiCorp's history of violations was used to inform the levels for its UE 399 PBR mechanism. Taking a similar approach with the PGE's violation history results in the targets presented below in Table 1. Staff sees these as a reasonable interim target to assess PGE's success. PGE's historical violations, Staff's proposed thresholds, and PGE's proposed and actual RVM spending can be seen in Exhibit 3301.

Table 1. Proposed RVM PBR Thresholds

Level	Threshold	Earnings Test
Level I	175<	+100 bps
Level II	260	+0 bps
Level III	345	-50 bps
>Level III	>345	-100 bps

Q. Staff is proposing a threshold that would increase PGE's opportunity to earn on RVM. Why?

A. Staff argues that customers are paying for quality service. Through this mechanism, we are trying to explicitly define what customers are paying for. Given PGE's past performance, Staff asserts that achieving less than 175 violations is possible – but rare. As such, Staff believes it is appropriate to offer an incentive for outstanding service.

Q. Does this mean that PGE can simply increase its budget to meet this exceptional threshold?

A. No. The targets are based on PGE planned spending levels. If the Commission decides to adopt Staff's proposed balancing account, then Staff would review any incremental spend in PGE's RVM budget. Aggressive accelerated spending in pursuit of this higher tier would not be deemed prudent. Second, included in Staff's updated proposal, is a condition that PGE's spend has to be at or below the budget included in rates for the Company to attain the benefit of Level I. This ensures that customers are truly receiving exceptional service given what they are paying for.

Q. Is Staff open to further discussion about the PBR RVM targets if they are adopted?

A. Yes. Staff prefers that targets for any PBR be regularly evaluated by the Commission, Staff, PGE, and stakeholders.

Q. Please summarize PGE's argument against Staff's proposed managerial disallowance.

A. PGE states that the managerial disallowance is inappropriate because the increased costs for vegetation management are largely out of its control. PGE cites the increased need for vegetation management across the region, high wages in California, and an increased internal demand for vegetation management due to extreme weather and wildfire management. Further, PGE argues that it has implemented incentives such as flexible schedules and year-round work to increase the local labor pool.

Q. Does Staff agree that the cost drivers listed above are creating inflationary pressure on PGE's RVM budget?

A. Yes. Staff also stated this in opening testimony.[16]

Q. Does Staff believe that PGE management has given this issue the attention it deserves given the magnitude of the cost increase?

A. No. Staff does appreciate PGE's implementation of a more flexible schedule and expanded scope of work. However, as discussed in Staff's opening testimony, PGE's RVM budget has increased **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. This cost increase is unprecedented and cannot be solved by more flexible schedules alone. Given the severity of the situation, Staff believes that PGE should be doing everything within reason to lower these costs. PGE complains in its testimony that Staff did not offer any suggestions for how to lower these prices.[17] Considering PGE's request for Staff's input, one potential solution may be to coordinate with the Local 125 to advertise the apprenticeship program at local college and high school job fairs. PGE could also further its equity goals by focusing its efforts in historically disadvantaged areas or through local community groups. While coordination with the Local 125 is seemingly not the norm, these cost pressures are extraordinary, and PGE should be doing everything in its power to lower these costs.

Q. Is Staff's managerial disallowance extreme?

A. No. Staff's proposed managerial disallowance represents roughly half a percent of PGE's proposed RVM budget.

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[16] Staff/2000, Stevens/20-21.
[17] PGE/2200, Bekkedahl-Putnam/11.

Q. PGE claims that Staff's managerial disallowance is inconsistent with Staff's proposed adjustment to PGE's Transmission & Distribution apprenticeship program. Do you agree?

A. No. These budgets are not related. That said, Staff is no longer proposing the adjustment to PGE's Transmission & Distribution (T&D) apprenticeship program.

ISSUE 2. MARGINAL COST STUDY & RATE SPREAD

Q. Please summarize your positions on PGE's marginal cost study from opening testimony.

A. In opening testimony, Staff did not offer any adjustments to PGE's marginal cost study.

Q. Did any other parties offer adjustments to PGE's marginal cost study?

A. Yes. AWEC proposed a handful of adjustments in Opening Testimony. AWEC proposed the following changes to PGE's generation marginal cost study:

1. Lowering the Effective Load Carrying Capacity (ELCC) of PGE's proxy battery resource from 83 percent to 57 percent.
2. Removing the capacity cost from the cost of wind energy.
3. Adjusting the salvage value of batteries from 5 percent to 0.5 percent.
4. Increasing the overnight capital cost of batteries from $1,195 to $1,214.
5. Removing wheeling costs from battery calculations.

AWEC also proposed shifting certain costs in PGE's customer marginal cost study to better align the customer marginal study with how PGE has unbundled these costs in its revenue requirement.[18]

Q. How did PGE respond to AWEC's proposals?

A. PGE largely incorporated AWEC's proposed changes to the customer marginal cost study, but the Company suggested that PGE wait until the next rate case to assess the inclusion certain departments to ensure that they are allocated appropriately. PGE rejected AWECs proposed changes 1

[18] AWEC/300, Kaufman/4-5.

and 2 to the generation marginal cost study above but agreed with proposed changes 3 through 5.[19]

Q. Why did PGE disagree with AWEC's proposal to lower the ELCC of PGE's proxy battery resource from 83 percent to 57 percent?

A. PGE stated that the 83 percent ELCC proposed in its opening testimony calculated using the standard approach for estimating resource capacity contributions to a tuned system. Similar to the energy portion of the study, PGE assumed a 2024 commercial online date (COD) for the battery resource whereas the IRP assumed a 2026 COD. PGE maintained that it was appropriate to keep the CODs the same for both the capacity and energy portions of the study.

Further, PGE noted that estimating marginal cost is an imprecise exercise. AWEC's suggested parameterization would have created a large swing in cost allocations towards residential customers and away from large industrial customers. PGE warned against using imprecise technical assumptions to justify a large departure in the rate spread. Lastly, PGE updated the Company's ELCC figure to 80 percent to reflect its latest estimate.

Q. Does Staff agree with AWEC's proposed ELCC adjustment?

A. No. Staff largely agrees with PGE on this issue and does not offer an adjustment to PGE's updated 80 percent ELCC figure. It is likely that the ELCC drop was due to the peak period moving to another part of the year.

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19 PGE/2500, Macfarlane-Keene/10 at 2-7.

If that is the case, the battery is still present and available to meet system peak throughout the year. Therefore the presumption should be that the ELCC of the battery should not fall as the loss of load probability moves to another hour, hours, or season/month.

Q. Why did PGE disagree with AWEC's proposal to remove the cost of capacity from the cost of wind energy?

A. PGE stated that the treatment of wind in this rate case is in line with how the marginal cost of wind was calculated in UE 394. PGE also similarly argue that removing the capacity cost of wind would result in a large cost allocation swing from industrial to residential ratepayers.

Q. Does Staff agree with AWEC's proposal to remove the cost of capacity from the cost of wind energy?

A. No. Again, Staff largely agrees with PGE on this issue. Staff also notes that the calculation used to identify the capacity value of wind in AWEC's proposal is extremely sensitive to the location of the proxy wind resource. PGE's estimated ELCC for Montana wind is significantly higher than in any other location. If this adjustment were to be made in the future, it should be done with much more robust assumptions. Furthermore, the mechanics of the subtraction of capacity costs does not fit with a variable generation world. For example, for a random out generator that provides zero capacity, it makes no sense to subtract out capacity costs. The resource is being added purely for energy reasons and as such no capacity cost reduction should occur.

Q. Does Staff agree with AWEC's other proposed changes to the generation marginal cost study?

A. Yes. Staff views proposed changes 3-5 as reasonable.

Q. Does Staff agree with AWEC's proposed changes to the customer marginal cost study?

A. Yes. Staff also finds PGE's proposal to delay the inclusion of certain departments to be reasonable. However, Staff main concern remains unaddressed. That is that there are substantial distribution and transmission investments that PGE has noted are being driven by a select few customers and yet PGE has not attributed those costs to those customers.

Q. Please summarize your positions on PGE's proposed rate spread from opening testimony.

A. In opening testimony, Staff proposed that the transmission and distribution revenue requirement related to the Hillsboro Reliability Project and the Horizon Keeler No. 2 120 kV line be removed from all schedules excluding Schedules 89, 489, and 90.[20]

Q. How did PGE respond to this proposal in its reply testimony?

A. PGE disagreed with Staff's proposal. PGE had two main arguments in support of its position. First, PGE claimed that this proposal would set a new precedent. Since these projects were deemed to be improvements for the entire system, its costs were spread in the marginal cost study as any

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[20] Staff/2000, Stevens/38-40.

other project would. PGE argues that assigning a project's costs to the customer class that is largely responsible for these costs by situs opens the door to rates based on geographic location and customer class. PGE gives the example that substations built for new neighborhoods could be argued to be situs assigned to Schedule 7 customers by this logic. PGE also argues that this proposal violates Bonbright's principles of cost causation and price stability.

PGE's second argument is that the Hillsboro Reliability Project is largely not yet in service, and the Horizon Keeler No. 2 230 kV is not yet in service.

Q. How do you respond to PGE's characterization that Staff's proposal may have unintended consequences?

A. Staff disagrees. The point of the marginal cost study is to reflect costs of the system in a scorched earth or steady state environment. The marginal cost study reflects neither. Staff is observing large investments for large commercial customers that is not reflected in the marginal cost studies. As such, the studies are not representatives of marginal costs PGE's system is incurring.

Q. How do you respond to PGE's assertion that Staff's proposal does not assign costs to cost causers?

A. Staff disagrees. Staff is concerned that, as currently constructed, PGE's distribution and transmission marginal cost studies do not properly allocate the costs of these projects. Judging by the project justification forms submitted by PGE in response to OPUC DR 586, some of the projects that PGE is proposing to put into base rates seem to largely benefit a single customer or very small group of large customers. Some excerpts from these project justification forms can be found below:

[BEGIN CONFIDENTIAL]

[redacted]

[redacted]

[redacted]

[redacted]

[END CONFIDENTIAL]

Further, in PGE's whitepaper on the Hillsboro Reliability project, **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**. Given PGE's current transmission marginal cost study effectively assigns transmission costs by 12-month coincident peak (CP), Staff would contend that this is not allocating costs to cost causers if large projects are being directly caused by new large load. Further, in PGE's distribution marginal cost study allocates cost for subtransmission and substations by effectively allocating costs by class non-coincident peak (NCP). This does not consider the geographic concentration of large load customers and the additional strain this puts on the local transmission and distribution system. While it may be true that residential customers have the largest NCP of any class, this load is spread out over the system. As such, NCP growth in the residential class will not have the same incremental cost as NCP from a large load customer. Put differently, the incremental costs caused by large load customers is not being appropriately borne by those customers.

As it stands, Schedule 7 customers are allocated roughly 60 percent of subtransmission and substation costs whereas Schedule 85, 89, and 90 customers are only allocated 15 percent. For transmission costs, Schedule 7 customers are allocated 48.3 percent of costs whereas Schedule 85, 89, and 90 customers are allocated roughly 30 percent. Staff is concerned about this potential mismatch in who is causing these costs and who is allocated these costs.

Q. How do you respond to PGE's assertion that these costs are not relevant as the projects are largely not complete?

A. Staff disagrees. Marginal cost studies typically reflect facilities planned in the future whether it is the replacement of all distribution facilities or the addition of generation resources over the next few years. Marginal cost studies have never included only costs of facilities currently in place. They are always forward looking.

Recently Oregon, and in particular PGE's service territory, has attracted many large customers. Many of these customers are in the energy intensive tech sector, and additional energy intensive tech companies have indicated plans for expansion in PGE's service territory.[21] Suffice to say, the issue of T&D upgrades related to large new load will only become an increasingly important issue. As PGE indicated, making costs predictable and clearly communicated will be important for these customers. Staff is concerned that the current cost allocation methodology will lead to residential customers cross subsidizing incremental T&D costs that are mostly, if not directly, caused by large load customers.

Q. Is Staff proposing changes to PGE's transmission and distribution marginal cost studies in this rate case?

A. Staff is not prepared to offer adjustments to PGE's transmission or distribution marginal cost studies at this time. Staff's attention was only recently brought to the potential magnitude of this issue. Any potential adjustments to PGE's transmission and distribution marginal cost study will

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[21] For example, Intel has recently signaled an expansion in the Hillsboro area. The company Analog Devices has also announced an expansion in the Beaverton area.

need to address the issue holistically and will likely take more time on Staff and PGE's part. Staff would like PGE to respond to these concerns in its next round of testimony and attempt to quell these concerns with an updated allocation methodology in its next rate case. However, until the issue is thoroughly analyzed, Staff recommends the Commission take the PGE marginal cost study with some suspicion and not be determinative of large rate spread changes. For example, Staff could support an equal percentage increase in rates as a reasonable result given the uncertainty in the accuracy of the marginal cost study.

Q. Is Staff still proposing its adjustment to rate spread indicated in opening testimony?

A. Yes. In the absence of a more comprehensive solution, Staff views this as a viable interim solution in the context of this rate case alone.

Q. Does Staff have any other potential solutions for this problem?

A. Yes. Staff would also like to propose a change to Schedule 300, Rule I – PGE's Line Extension rule. Please see Staff/4100 for further discussion on this issue.

ISSUE 3. RATE DESIGN

Q. Please briefly summarize your positions on rate design from opening testimony.

A. Staff took many positions on rate design in opening testimony. These positions are listed below:

Residential Basic Charge Increase: Staff had no objection to PGE's basic charge increase, but broadly discusses the disparate impacts of increases to the basic charge across environmental justice communities in Staff Exhibit 600.

Schedule 32 and Schedule 83 Basic Charge Increase: Staff did not oppose PGE's proposed basic charge increase for Schedules 32 and 83. Staff also questioned the logic of maintaining a basic charge that is significantly lower than embedded cost for these customers.

Schedule 83 and 85 Generation Demand Charge Increase: Staff did not oppose PGE's proposal to increase Schedule 83 and 95 generation demand charge.

Rules and Regulations Changes: Staff proposed moving the discussion of PGE's Line Extension rule change to the WMP docket.

Flattening residential rates: Staff took no stance on flattening residential rates but did discuss the potential pros and cons of this change, particularly in the context of equity and cost causation. For an expanded discussion on the potential equity impacts of this policy, See Staff Exhibit 600.

Elimination of Schedule 7 Legacy Time-of-Use (TOU): Staff proposed blocking new enrollment, but preserving the schedule for customers who prefer to remain on the schedule.

Schedule 7 Time-of-Day (TOD) Peak Hours Change: Staff did not support PGE's proposal to extend the Schedule 7 TOD on-peak hours to include the hour ending in 5pm.

Decoupling: Staff opposed the reinstatement of decoupling, particularly with PGE's condition of acceptance of its PCAM modifications.

Applying Schedule 102 to Basic Charge: As mentioned above, Staff proposed applying the credit to customers received via the Residential Exchange Program (REP) to customers basic charge as opposed to a per kWh credit. Staff also indicated that a per kWh cap at 2,000 kWh would also be acceptable.

Non-Residential TOD Reform: Staff proposed reforming the TOD window for Schedules 83, 85, 89, and 90 to better reflect system prices.

Longer-Term Goals: Staff discussed its interest in pursuing opt-out TOD for Schedule 7 and a separate equity minded tariff.

Q. Did PGE or any other party respond to either PGE's proposed residential basic charge increase or Staff's response?

A. CUB also indicated that it does not object to PGE's proposed basic charge increase.[22]

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[22] CUB/300, Gehrke/15.

Q. Did PGE or any other party respond to either PGE's proposed non-residential basic charge increase or Staff's response?

A. No.

Q. Did PGE or any other party respond to either PGE's proposed increase to the Schedule 83 and 85 generation demand charge or Staff's response?

A. No.

Q. Did PGE or any other party respond to either PGE's proposed Line Extension rule change or Staff's response?

A. Yes. PGE agreed that the topic should be discussed in more detail within the context of the Wildfire Mitigation Plan (WMP) review. PGE also noted that requiring customers to underground line extensions in high-risk fire zones may be cheaper if the alternative is to underground the line at a later date.[23]

Q. Please summarize Staff's opening testimony on flattening residential rates.

A. Staff pushed back on PGE's assertion that there was strong evidence that inverted block rates disproportionately hurt low-income customers. To make this claim, PGE used Income Qualified Bill Discount (IQBD) participation as a proxy for income level. Staff argued that since the IQBD program is not fully matured, early adopters who may have the most to gain from participation may be skewing PGE's analysis. Further, Staff pointed to the

[23] PGE/2600, Macfarlane-Pleasant/40-41.

large national literature on the relationship between energy and income which points to a positive correlation. Staff also pushed back on PGE's assertion that flattening rates will unequivocally encourage electric vehicle (EV) adoption. Staff showed that customers consuming over 1,200 kWh of electricity will receive lower bills than with inverted block rates. As such, EV owners who otherwise have low to medium levels of energy consumption will actually have higher bills from this change. Lastly, Staff argued that having an increasing block does not muddle the price signal from the TOD rate. Staff argued that the price signals encourage to separate behaviors, one related to the total amount of energy consumed and the second to when that energy is consumed.

However, Staff did not ultimately make a recommendation on this topic. Staff presented ambiguous evidence regarding the relationship between higher usage and system costs. Staff intends to provide a deeper look into the topic in this round of testimony.[24]

Q. Did any other parties comment on PGE's proposal to flatten residential rates?

A. Yes. CUB did not oppose PGE's proposal.[25]

Q. How did PGE respond to Staff's discussion?

A. PGE further argued its point that low-income customers are disproportionately hurt by inverted block rates. The Company used

[24] Staff/2000, Stevens/47-54.
[25] CUB/300, Gehrke/16-17.

purchased estimated income data to estimate that low-income median usage is roughly 6 percent higher than non-low-income customers. PGE explains this difference by combining this estimated income data to show that low-income are often more electrified than non-low-income customers.[26] The Company also provides some evidence that the Pacific Northwest may be a national outlier in the relationship between income and energy consumption.[27] PGE did not necessarily push back against Staff's comments regarding flat rates ability to incentivize transportation electrification. However, PGE did argue that customers whose consumption is currently around the median, who adopt both EVs and heat pumps, may exceed the consumption threshold for flat rates to make them better off.[28] Lastly, PGE argued that the price signal sent by TOD rates is so much larger than the increasing block that it effectively overtakes the price signal from the increasing block.[29]

Q. How do you respond to PGE's new evidence regarding low-income energy consumption?

A. Staff appreciates PGE's analysis on this issue and remains open to the possibility that it may be true. Staff does have reservations about the accuracy of the data used in PGE's analysis. Income data is notoriously difficult to both collect and comprehend as there are countless ways to

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26 PGE/2600, Macfarlane-Pleasant/30-32.
27 PGE/2600, Macfarlane-Pleasant/29-30.
28 GE/2600, Macfarlane-Pleasant/33 at 1-3.
29 PGE/2600, Macfarlane-Pleasant/33 at 6-11.

measure income. The data PGE uses is estimated income data, which obviously will have a margin of error. Before accepting this analysis as concrete evidence, Staff would have to better understand this data set and its reported accuracy. Second, PGE tells a convincing story about low-income heating electrification being the primary driver of this phenomenon. Again, Staff is open to this explanation of the causal driver but is remains skeptical of the data accuracy. In PGE's Opening Testimony regarding load forecasting, it claimed that its data on household heating fuel was too inaccurate to use for the propose of load forecasting.[30] As such, Staff has a difficult time fully accepting this analysis, but does find it helpful in understanding the relationship between income and energy usage.

Q. How do you respond to PGE's argument about customers who adopt both heat pumps and EVs benefitting from flattened rates?

A. Staff's example of EV adaptors not unequivocally benefitting from flattened rates was based on a hypothetical customer consuming the median amount of energy per month. Staff would contend that some households in this category may already have electric heating and cooling. Staff still contends that some households may still be worse off under flattened rates even if they fully electrify. To be clear, Staff is not arguing that all or most customers will not benefit. Staff's argument is simply that a potentially non-trivial number of customers may actually receive the opposite price signal from rate flattening.

[30] PGE/1100, Riter-Greene/10.

Q. How do you respond to PGE's argument that the increasing block price signal is overshadowed by the Time-of-Day (TOD) price signal for TOD customers?

A. In general, Staff agrees with this statement. In Opening Testimony, Staff argued that the price signals were distinct. As it stands the inverted block price signal is fairly small. That said, even if customers largely do not respond to it, it does still have the opportunity to align costs with cost causers – assuming that customers who consume more cost the system more. However, as discussed in Staff/3100, cost causation should not be the only metric used in evaluating changes to rate design.

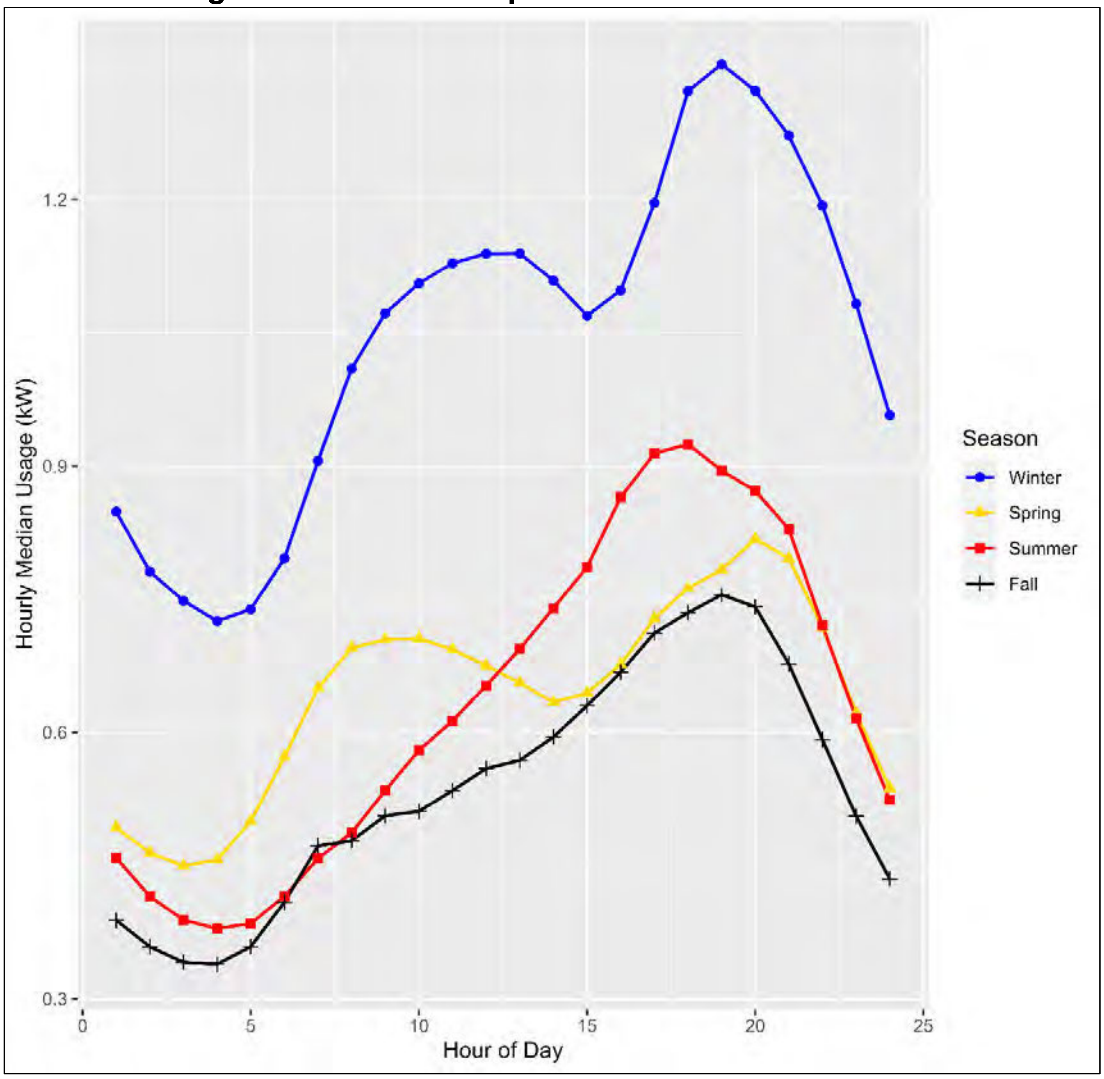
Q. Has Staff been able to identify any new pieces of evidence that definitively answer whether high usage customers are unambiguously more expensive to serve?

A. Somewhat. In OPUC DR 781, Staff did request hourly usage data for different subsets of residential customers. Staff found that on average, IQBD customers have relatively high and peaky winter loads with much smaller seasonal variation in other months.[31] This result does support PGE's assertion that low-income customers may consume more because they have electric heat. However, Staff is still cautious about drawing conclusions from this data due to the potential sample selection bias

[31] Staff uses seasons as defined by the Western Resource Adequacy Program (WRAP).

discussed in opening testimony.[32] The usage profile for IQBD participants can be seen below in Figure 3.

Figure 3. IQBD Participant Seasonal Load Profile



Further, this data does indicate that customers with above average or extremely high consumers have higher load factors. Conversely, customers with median or low levels of monthly consumption have peakier loads. This likely stems from the fact that these customers' load that is not related to

32 Staff/2000, Stevens/48-49.

temperature control is so low, that when they either heat or cool their house, it accounts for a large relative increase in consumption. Staff calculated a back-of-the-envelope load factor for each of these usage profiles. For this calculation, Staff compared the total load of the customers in each profile to the profiles average load at **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. This hour was indicated as the hour with the highest Loss of Load Probability (LOLP) both on weekdays and weekends in PGE's confidential response to OPUC DR 778. The results of this analysis can be found in Table 2 below. As a robustness check, Staff also calculated this metric for the hours of 7pm-9pm during the summer and winter. This is a much broader definition of when the system in strained. However, the result was generally the same, smaller residential customers have a lower load factor than larger residential customers.

Table 2. Load Factor by Consumption Level

Average Monthly Load	Crude Load Factor
<300 kWh	.56
~750 kWh	.61
~2,000 kWh	.81
>15,000 kWh	1.16

Q. Given this new evidence, does Staff now support flattening rates?

A. Not necessarily. Staff is not claiming that the analysis described above is definitive. Staff merely sees it as another piece of evidence describing the potential consequences of rate flattening. In summary, Staff sees the following as potential consequences of flattening rates:

1. Bills for customers who consume small to medium amounts of energy on average will increase.
2. There is some suggestive evidence that low-income customers may benefit from this change on net.
3. This change may encourage transportation electrification (TE) for customers who already consume an above average amount of energy. However, it may make TE less appealing for customers who consume at or above the average amount of energy.
4. There is suggestive evidence that low usage Schedule 7 customers are relatively costlier to serve. As such, flattening rates may be more aligned with cost causation principles.

In short, flattening rates will be beneficial to some and detrimental to others. However, flattening rates may be more in line with cost causation principles. Due to the ambiguous nature of rate flattening, Staff simply presents these facts to the Commission and other interveners without offering a recommendation. Staff does however note that the impact to low usage customers could be mitigated the acceptance of Staff's proposal to apply the Residential Exchange Program (REP) credit to customer's basic charge.

Q. Please summarize Staff's opening testimony on the Legacy Time-of-Use (TOU) option.

A. Staff agreed with PGE that the Legacy TOU option should end new enrollment. However, Staff argued that it is reasonable to keep the Legacy TOU option open for customers who are currently enrolled and prefer to stay in the program.

Q. Did any other parties' comment on PGE's proposal to retire the Legacy TOU option?

A. Yes. CUB agreed with PGE that the option should be retired.

Q. How did PGE respond to Staff's proposal?

A. PGE argued that the fact that some customers remain on the schedule does not necessarily indicate that it is their preference. It may also mean that they may simply be unaware of the newer TOD option. PGE also argued that half of the customers on the Legacy TOU option would see a savings if they had switched to the TOD or standard Schedule 7 rate. PGE also argues that there are some costs to maintaining this schedule but does not offer an estimate as to the magnitude of this cost.

Q. How does Staff respond to PGE's reply?

A. Staff notes that if half of current Legacy TOU customers would have been better off, this implies half would be worse off. PGE indicates that some customers could see material decreases to their bills if the customers had switched, but did not indicate whether the customers who would see bill increases would be materially affected. Staff understands the arguments for retiring the schedule, but it is difficult to weigh these against the cons without an estimate of the cost of maintaining the option.

Q. Please summarize Staff's opening testimony on PGE's proposal to modify the on-peak window for residential TOD customers.

A. Staff did not support PGE's proposal to change the on-peak window for residential TOD customers to include the hour ending in 5pm. Staff argued that the structure TOD schedule should only be changed to better align retail and system prices. In PGE's opening testimony, PGE's primary argument for making this change was to temper the price increase in the on-peak period.[33] Staff argued that PGE should strive for long-term consistency in the structure of its TOD option and that modifying a core component of the offering, the on-peak window, in order to mitigate a price change in is in conflict with this principle.

Q. Did any other parties comment on the proposed modification to the on-peak window?

A. Yes. CUB also submitted testimony on this issue. CUB also argued that the TOD schedule should remain unchanged. CUB further highlighted that a third-party evaluation of the pricing structure is approaching completion. CUB argues that changing the pricing structure of the program before the evaluation is complete is premature.

Q. How did PGE respond to Staff and CUB's testimony?

A. PGE argued that the hour ending 5pm is still a high-cost hour for wholesale energy prices and that extending the on-peak window to begin at 4pm would still be in line with cost causation principles. PGE also pointed out that this

[33] PGE/1300, Macfarlane-Pleasant/44-45.

change would align the on-peak window with demand response events. Lastly, PGE indicated that it would be open to modifications to the pricing windows other than the extension to the hour ending in 5pm.

Q. How does Staff respond to CUB and PGE's comments?

A. In general, Staff is cautious to make any changes to the TOD windows. If a modification is made, either in this or a future rate case, Staff would prefer it be long lasting change. Staff agrees with CUB, that implementing a change directly before a comprehensive study on the effectiveness of the option seems premature. Staff would prefer to have time to read and digest the evaluation before any changes are made. Changing the structure of the program now will effectively render the evaluation of the current program largely useless. Staff does agree that the hour ending in 5 PM is an hour with elevated system costs. However, drawing a line at what is "on-peak" and "mid-peak" will always be somewhat subjective. Staff believes that the current on-peak window is a reasonable approximation to PGE's system costs.

Q. Please review Staff's position on decoupling in opening testimony.

A. Staff argued against reestablishing decoupling for PGE in opening testimony. In short, Staff argued that decoupling largely passes short-term business risk from shareholders to rate payers and is not necessary to promote energy efficiency and other environmental goals. Further, PGE has indicated that it will only support reestablishing decoupling if its PCAM proposals are accepted. Staff does not support PGE's PCAM proposals.

Q. Did any other parties discuss decoupling?

A. Yes. NRDC and NWEC submitted voluminous joint testimony in support of reestablishing decoupling.

Q. Please briefly summarize NRDC and NWEC's testimony.

A. NRDC and NWEC continued their objection to the Commission's decision to accept a Partial Stipulation in UE 394 which eliminated PGE's decoupling mechanism. NRDC and NWEC argue that without decoupling energy efficiency investment in PGE's service territory will fall.[34] As a corollary, NRDC and NWEC argue that the Energy Trust of Oregon (ETO) is an insufficient guard rail against PGE's misaligned incentives.[35] NRDC and NWEC also argue that PGE will make investments or push policy which will spur electrification through inefficient means.[36] NRDC and NWEC argue that decoupling will negatively affect distributed energy resource (DER) adoption.[37]

Q. Did PGE respond to Staff and intervener opening testimony on decoupling?

A. Yes. PGE largely reiterated its positions from Opening Testimony. PGE states that it believes that decoupling can have positive effects if "implemented correctly". While PGE does not say explicitly what this means, it would seem that a soft cap allowing for full pass-through of fixed

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34 Cavanagh/8-9.
35 Cavanagh/17-18.
36 Cavanagh/11 at 4-16.
37 Cavanagh/15-16.

costs paired with a PCAM mechanism which effectively allows for full pass-through of fuel costs are requisite for its definition of “correct implementation”.

Q. Does Staff agree with PGE’s position?

A. No. As PGE’s position did not change, Staff refers to its discussion in Opening Testimony to respond to PGE’s comments.[38]

Q. Does Staff agree with NRDC and NWEC that energy efficiency is vital tool in decarbonizing the economy?

A. Yes. Staff unambiguously agrees with NRDC and NWEC on this point. Staff works diligently with the ETO to further its mission and promote energy efficiency across the state.

Q. Do you agree with NDRC and NWEC’s argument that decoupling is vital to maintain support for energy efficiency investment?

A. No. Staff discussed this issue in opening testimony.[39] To reiterate, unlike other states, such as California, PGE works with the ETO but has limited influence over its activities.

Further, in support of their argument, NRDC and NWEC cite a ACEEE white paper published in 2015.[40] Staff reviewed this paper and found its results dubious. First, this is not a peer-reviewed paper, but instead a publication from an energy efficiency advocacy group. The finding that is

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38 Staff/2000, Stevens/58-63.
39 Staff/2000, Stevens/61-62.
40 M. Molina & M. Kushler, Policies Matter: Creating a Foundation for an Energy Efficient Utility of the Future (June 2015).

quoted in NRDC and NWEC's testimony is particularly troubling. The paper states that utilities in states with decoupling "had much higher energy efficiency spending and savings". What the authors of the paper go onto to say, but NRDC and NWEC leave out of their testimony is all but one state at the time the paper was written had decoupling policies, but no Energy Efficiency Resource Standard. As such, the isolated effect of decoupling cannot be identified in the study. This is particularly troubling as NDRC and NWEC argue that Oregon's Energy Efficiency mandates aren't enough to counteract PGE's financial incentive.[41] Staff does not believe the article is convincing.

To Staff's knowledge there is no paper that has causally identified a link between decoupling and energy efficiency investment. While Staff remains open to the possibility that this link exists, Staff does not believe that the evidence that NRDC and NWEC points to is sufficient to draw this conclusion. Further, even if a causal link was found at the national level, since Oregon has the ETO, Staff would argue that the national effect may not apply here. Staff plans to continue to monitor the progress of the ETO and Energy Efficiency investment at large in the state. If Energy Efficiency investment dramatically falls, Staff is open to rediscussing this issue if it seems like it may be a driver of this change.

Q. Does NRDC and NWEC agree that having the ETO control ratepayer funded Energy Efficiency investments differentiates Oregon from other states?

[41] Cavanagh/18 at 5-9.

A. No. NDRC and NWEC largely ignore the role of the ETO in their testimony. NRDC and NWEC push back on Staff's argument in their opening testimony stating that the Commission rejected this argument in Order No. 09-020:

> We find this position unpersuasive, because PGE does have the ability to influence individual customers through direct contacts and referrals to the ETO. PGE is also able to affect usage in other ways, including how aggressively it pursues distributed generation and on-site solar installations; whether its supports improvements to building codes; or whether it provides timely, useful information to customers on energy efficiency programs. We expect energy efficiency and on-site power generation will have an increasing role in meeting energy needs, underscoring the need for appropriate incentives for PGE.[42]

Staff argues that the energy landscape has changed dramatically in Oregon since this order was written. First, when this order was written, the ETO had been established for roughly seven years. Today, the ETO is well established and has more than 20 years of institutional experience behind it. The ETO is not largely reliant on residential referrals from PGE. As a simple example, when searching the term "energy efficiency Portland" on Google, the ETO is the second result only to the City of Portland's website.[43] By contrast, PGE's energy efficiency webpage (which also links to the ETO's website) is seventh.[44]

Further, DER technology has advanced rapidly since 2009. The National Renewable Energy Lab (NREL) found that installed residential PV system prices have been more than halved since the time Order No. 09-020 was

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[42] Order No. 09-020, p. 27.
[43] Google page can be found here.
[44] PGE's website can be found here.

written.[45] There are many private solar installers in PGE's service territory. Customers do not need to involve PGE in their decision to install a PV array other than to confirm the infrastructure in their area can support it and to opt-in to net metering.

Lastly, to Staff's knowledge PGE is not involved in building code discussions. For example, PGE is not involved in the Oregon Energy Building Code Stakeholder Panel, although the ETO is. Staff agrees that in when the referenced order was written, the concerns of the Commission were very relevant. However, the markets both for energy efficiency investments and DERs has matured beyond the need for direct utility interaction.

Q. Does Staff believe that PGE plays a major role in whether homeowners, builders, or businesses decide to invest in Energy Efficiency or DERs?

A. No. As discussed above and in opening testimony, the public's understanding, and access to information regarding Energy Efficiency investments and DERs has changed dramatically since decoupling was adopted.[46] Individual customer's decisions to invest in Energy Efficiency investments and DERs will largely depend on the price of energy and the price of the investment. For lower income residential customers, credit constraints may be a factor as well. The ETO has well-advertised incentive programs to help these customers afford both weatherization improvements and efficient heat pumps.[47]

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[45] See summary here.
[46] Staff/2000, Stevens/61-62.
[47] ETO's Savings within Reach program page can be found here.

Q. Does Staff agree with NRDC and NWEC's assertion that reestablishing decoupling will affect future EV efficiency?

A. No. NRDC and NWEC point to an analysis that claims that there is a massive untapped potential for EV efficiency. NRDC and NWEC argue that if EVs were to become more efficient, that PGE would lose money.[48] The implication is seemingly that without decoupling PGE will oppose energy efficiency advancements in EVs. Staff is confused about this argument. To Staff's knowledge, PGE is not pursing any research in EV manufacturing technology, nor does it have any control over an EV manufacturer. Staff sees advancements in EV technology as largely exogenous to PGE's business.

Q. Does Staff agree with NRDC and NWEC's argument that EE investments have the ability to materially reduce PGE's margins?

A. No. Staff believes that NRDC and NWEC have a fundamental misunderstanding about how decoupling affects utility margins. When rates are set in a rate case, they are meant to have the utility recover its revenue requirement conditional on an accurate load forecast. The load forecast in Oregon is based on a forward-looking test year, in this case 2024. If energy sales in the test year are lower than the load forecast predicted, then PGE will recover less than its fixed cost revenue requirement and vice versa because rates are not set on a fixed/variable basis. When PGE comes in for its next rate case, a new load forecast will be estimated, and the process

[48] Cavanagh/12.

will repeat. As such, any "windfall" gains PGE would potentially experience would be based on a deviation in load from the short-term load forecast.

In order to negatively affect PGE's margins, a large amount of energy efficiency or DERs would have to be unexpectedly installed over a very short period of time. Further, for any decrease in energy efficiency to affect PGE's margins, there would have to be an abrupt and unpredictable stop to energy efficiency investments. Further, PGE incorporates forecasted ETO savings directly into its load forecast.[49] PGE also forecasts DER and EV adoption using a model developed by a third party and examined by the Commission.[50] If there is a more slowly developing trend, like PGE passively resisting ETO projects, the load forecast would likely be able to pick up this trend and PGE would not be able to materially benefit from it. The only way PGE could benefit from a change in norms like this, is by not returning for a rate case for an extended period. However, given the amount of projected plant investment PGE is expected to put into service in coming years, Staff highly doubts that PGE will choose to delay rate cases for the de minimis increase to its margins that the above scheme could make.

NRDC and NWEC's thought experiment of the effect of a multi-year program is based on two questionable assumptions.[51] First, NRDC and NWEC assume that this large multi-year project would have not been

[49] PGE/1100, Riter-Greene/16.
[50] See dockets UM 2005 and UM 2197.
[51] Cavanagh/14-15.

anticipated by the ETO and would not be built into its forecasted incremental savings and accounted for in PGE's load forecast. Second, NRDC and NWEC assume that PGE would not come in for a rate case over the hypothetical 5-year period. As stated above, Staff does in not under the impression that PGE will forego recovery of large capital projects in order to avoid resetting the load forecast. These rosy assumptions greatly overstate the potential impact of energy efficiency investments to PGE's fixed cost recovery.

Q. Can the absence of decoupling materially affect PGE's margins in any way?

A. Potentially. However, this will not come from energy efficiency and DER investment, but instead from unexpected market or weather fluctuations. Decoupling shifts the risk, both positive and negative, of these economic and weather drivers onto ratepayers. As stated in opening testimony, Staff believes that this risk should be borne by the Company.[52]

Q. How do you respond to NDRC and NWEC's claim that the "hard cap" in PGE's previous decoupling mechanism promoted load forecast manipulation?

A. Staff agrees that there could be an incentive to manipulate the load forecast under the previous decoupling mechanism. Staff also argues that many parties may have an incentive to manipulate the load forecast without decoupling. Staff does recognize that with a soft cap, like PGE is proposing,

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[52] Staff/2000, Stevens/ 60-61.

there is less incentive to manipulate the load forecast. However, like as Staff discussed in opening testimony, Staff would simply prefer that PGE have less subjective control over the load forecast. Parties have an agreement in principle to accept Staff's methodological changes to the load forecast and for PGE to work with Staff and Interveners between rate cases to improve the objectiveness of the forecast. Staff will continue to work on this issue to ensure that the load forecast is not manipulated either with or without decoupling.

Q. Please summarize Staff's testimony on Schedule 102.

A. In opening testimony, Staff proposed that the Residential Exchange Program (REP) credit be distributed to customers on a per-customer basis as opposed to a per-kWh basis. Staff made this suggestion as the REP credit is currently applied as a flat credit to all kWhs consumed by all qualifying customers. This means that customers with large loads receive a larger portion of the credit than customers with small loads.

Q. How did PGE respond to Staff's proposal?

A. PGE did not support Staff's proposal. PGE argued that Staff's proposal violates the spirit of the NW Power Act. PGE also argue that because high usage customers increase PGE's qualifying load, they should receive a greater share of the benefits. PGE also argues against putting a cap on the credit as it would effectively create an inverted block rate – something that PGE has been trying to remove for years.

Q. How do respond to PGE's claim that Staff's proposal violates the spirit of the NW Power Act?

A. Staff recognized in its Opening Testimony that PGE's qualifying load does have some impact on the amount of funds received.[53] However, both here and in opening testimony, Staff asserts that the size of the of pie is fixed, and each utility's load only partially determines what share of the pie each utility receives.

Q. How does BPA allocate the REP credit?

A. Each year there is a scheduled amount to be paid out to all six utilities in aggregate. Table 3 below is the yearly table of payouts to the six IOUs included in the 2012 BPA REP settlement.

53 Staff/2000, Stevens/65 at 8-10.

Table 3. Schedule of REP Settlement Benefit Payouts to IOUs

Fiscal Year	Scheduled Amount (millions)
2012	182.1
2013	182.1
2014	197.5
2015	197.5
2016	214.1
2017	214.1
2018	232.2
2019	232.2
2020	245.2
2021	245.2
2022	259.0
2023	259.0
2024	273.6
2025	273.6
2026	286.1
2027	286.1
2028	286.1

As is shown above, the total amount available to the six IOUs is fixed in each year. BPA calculates each IOU's share of the total scheduled amount by finding the difference between each IOU's Average System Cost and BPA's Reference Rate then multiplying it by each IOU's qualifying load. This formula means that there are multiple factors which determine how much of the REP credit is distributed to PGE:

1. PGE's Average System Cost,
2. PGE's qualifying load,
3. All other participating utility's Average System Cost,
4. All other participating utility's qualifying load, and
5. The BPA's reference rate.

So while it is true, that residential customers who have a higher load to allow PGE to receive more of a credit, there are many other factors at play as well. For example, if all consumers kept their consumption constant, and PacifiCorp customers consumed less, then PGE's allocation would also increase.

Q. How has the Commission historically treated the REP credit?

A. The Commission has a long history of treating the REP credit both as a mixture of a per customer and as a usage benefit. Namely, the Commission has put usage caps on the number of kWh that the credit applies to. Prior to UE 335, PGE had a 1,000 kWh cap on its REP credit; and, in UE 399, PacifiCorp set a cap at 2,000 kWh cap on its REP credit. Staff suggested this alternative in Opening Testimony.[54] However, PGE argued that this would go against its stated goal of flattening the residential volumetric rate. Part of the reasoning behind Staff's proposal was to allow for the opportunity for rates to be flattened, while ensuring that large usage customers do not receive an outsized portion of the benefits of the program.

Q. Do you agree with PGE's argument that some ratepayers will be made worse off by this decision?

A. Yes. As with the rate flattening proposal, there will be some customers who end up with higher bills and some that end up with lower bills because of this change. In Opening Testimony, Staff estimated that roughly 56 percent of all PGE customers and 50 percent of IQBD customers would see a bill decrease if this proposal was adopted.[55] PGE attempted to flip this on its

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[54] Staff/2000, Stevens/67 at 9-10.
[55] Staff/2000, Stevens/67 at 5-7.

head and argued that this means that roughly half of customers will see a bill increase.[56] Staff does not find this argument persuasive.

PGE also argued that IQBD customers on average consume more energy, than non-IQBD customers and will be hurt by this change. First, Staff reiterates that low-consuming IQBD participants will benefit from this change. Second, if IQBD participants do see bill increases because of this change, it will be mitigated by their bill discount. Lastly, both Staff and PGE have presented suggestive evidence that higher energy consumption among IQBD participants seems to be linked to heating in the winter. A more helpful and sustainable solution to this issue would be to target weatherization and heat pump programs to these households, rather than simply offering a small subsidy to their volumetric energy price.

Q. Would applying the REP credit to customers' basic charge have any secondary effect that is important to highlight in this case?

A. Yes. If PGE's rate flattening proposal is accepted, applying the REP credit to the basic charge can help mitigate the bill hike for low-consuming customers. Also, Staff argues that providing the REP credit on a per customer basis may make the benefit more tangible to customers. The current REP settlement is set to expire in 2028. A recent proposal by the BPA indicated that the agency may substantially decrease the amount of benefits given to IOUs.[57] If the benefit is more tangible to customers, there

[56] PGE/2600, Macfarlane-Pleasant/36-37.
[57] https://www.bpa.gov/energy-and-services/power/residential-exchange-program/post-2028-rep, at bullet point RAM 2022 REP Model.

may be more groundswell support behind keeping the benefits near current levels.

Q. Please summarize Staff's testimony on changing the TOD schedule for Schedules 83, 85, 89, and 90.

A. Staff argued that the current on-peak window for these customers, from 6 AM until 1 PM Monday through Saturday, is not aligned with PGE's system costs. Staff suggested that the schedule by modified but did not offer a particular schedule.

Q. How did PGE respond to Staff's proposal?

A. PGE indicated that it was open to updating the structure of the TOD windows for these customers but needed more time to do so. PGE suggested that it be done in a future rate case.

Q. How does Staff respond?

A. Staff appreciates PGE's willingness to look into the issue. Staff also understands that crafting a new structure for the TOD windows will take time. Staff also proposes that PGE host workshops between this and its next rate case to discuss its progress on the issue and to receive feedback from stakeholders.

Q. Please summarize Staff's testimony on longer-term goals and investigations.

A. In opening testimony, Staff discussed a desire to look into both an opt-out TOD rate for residential customers and an equity-minded schedule. Staff sees this combination of offerings as a potential solution to the issue of matching cost causation to cost causers without over-burdening disadvantaged communities.[58]

Q. Did PGE respond to either of these longer-term proposals?

A. No, although PGE maintains that opportunity in the final round of testimony.

Q. Did interveners bring up any new pricing issues in opening testimony?

A. Yes. CUB proposed lowering PGE's employee discount from 25 percent to 5 percent to be in line with the discount for low-income customers, and Wal-Mart proposed reforming Schedule 38.

Q. How did PGE respond to CUB's proposal to decrease the employee discount to 5 percent?

A. PGE argues that the employee discount and IQBD program are wholly unrelated, and that the employee discount is an important part of its compensation package. PGE also argues that other industries commonly offer employee discounts and that this issue would be particularly difficult to implement for unionized workers. Lastly, PGE argued that the Commission ruled in favor of PGE when CUB offered a similar argument in UE 197.

Q. Does Staff have a position on this argument?

A. No, although pricing signals are important and that includes PGE employees as well as well as incentives to have PGE employees residing in PGE's service territory.

Q. Please summarize Wal-Mart's proposed reform for Schedule 38.

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[58] Staff/2000, Stevens/70-71.

A. In opening testimony, Wal-Mart proposed that Schedule 38 be expanded to allow for customers whose demand has not exceeded 4,000 kW more than once in the preceding 13 months to be eligible for Schedule 38. Wal-Mart argues that it would allow moderately sized TE charging stations to be eligible for the schedule.

Q. How did PGE respond to Wal-Mart's proposal?

A. PGE pushed back on this proposal arguing that it could cause inter-schedule cross subsidization as the marginal cost study would not accurately reflect the system costs of the schedule. PGE indicated that it was open to working on a more comprehensive solution in a future rate case.[59]

Q. What is Staff's position on this proposal?

A. Staff supports Wal-Mart's proposal. Staff does share PGE's concerns regarding the potential for cost shifting. Staff plans on monitoring the potential cost shifting created by this change if it is adopted. Staff assumes that if this proposal is accepted, that PGE would join them in that effort and offer potential modifications if the Company has serious concerns.

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[59] PGE/2600, Macfarlane-Pleasant/33-34.

SUMMARY

Q. Please summarize your testimony.

A. In Opening Testimony, Staff had four main suggestions regarding routine vegetation management. First, Staff proposed the creation of a balancing account to track RVM costs. PGE agreed with this suggestion. Second, Staff suggested a RVM PBR mechanism be put in place to incentivize consistent vegetation management performance. PGE argued against this position in its Reply Testimony claiming that it was not necessary, and that the thresholds Staff proposed were not properly tailored to PGE's system. Staff adjusted its proposed thresholds in response but maintains the importance of the PBR mechanism. Third, Staff suggested that a system performance PBR mechanism be established to incentivize consistent service quality and network resilience. PGE argued against this position in its Reply Testimony claiming that it was not necessary. Staff has decided to withdraw this proposal but plans to continue to refine it for future Commission consideration. Lastly, Staff recommended a managerial disallowance of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** be imposed. PGE argued against this position in its Reply Testimony claiming that the increases to RVM costs are largely out of its control. Staff again argued against this and maintains its position for imposing a disallowance.

In Opening Testimony, Staff did not make any recommendations regarding PGE's Marginal Cost Study. However, Staff did recommend an adjustment to rate spread that would shift the cost for certain transmission and distribution projects to the schedules that necessitated the investments. In Opening Testimony, AWEC argued that certain changes be made to the generation and customer marginal cost studies that, on net, would shift costs from industrial customers to residential customers. PGE argued against a subset of these changes in its Reply Testimony. In general, Staff agrees with PGE. Staff discusses its response to PGE's Reply Testimony regarding costs how transmission and distribution projects are spread in Staff/4100. Given the Staff concerns on the PGE marginal cost study, an equal percent increase may be warranted.

For rate design, Staff had several recommendations in Opening Testimony. Staff's main suggestions are summarized below:

- The Legacy TOU schedule should not be fully retired, but PGE may not allow new enrollments.
- The peak hours for residential TOD should not be changed.
- Decoupling should not be reimposed as suggested by PGE.
- The RAP credit should be applied on a per-customer basis.
- The on-peak window for Schedules 83, 85, 89, and 90 should be modified to better reflect system costs.
- An equity focused rate schedule and an opt-out TOD Schedule 7 should be discussed as potential long-term goals.

In Reply Testimony, PGE agreed with Staff's suggestion to look into reforming the TOD schedule for Schedules 83, 85, 89, and 90 and did not comment on Staff's final point about longer-term goals. However, PGE disagreed with Staff on all other points listed above. In Opening Testimony, NRDC and NWEC disagreed with Staff's position to not reinstate decoupling. In Opening Testimony, Wal-Mart also suggested expanding Schedule 38, which Staff supports. In this Rebuttal, Staff maintains all of its original positions from Opening Testimony including Staff's middling position on flattening residential rates.

Q. Does this conclude your testimony?

A. Yes.

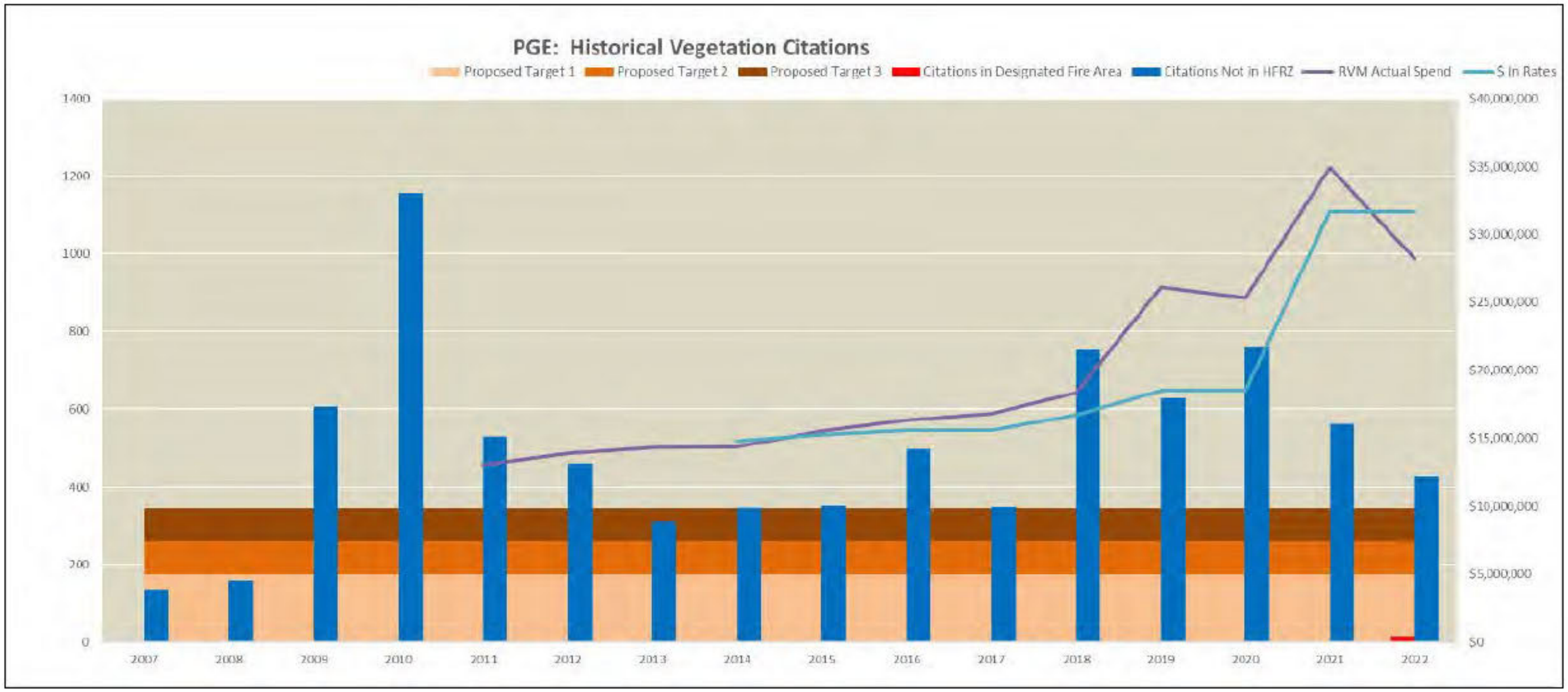
CASE: UE 416
WITNESS: Bret Stevens

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 3301

PGE's Vegetation Citations and Proposed Thresholds

August 22, 2023


PGE: Historical Vegetation Citations
Proposed Target 1
Proposed Target 2
Proposed Target 3
Citations in Designated Fire Area
Citations Not in HFRZ
RVM Actual Spend
$ in Rates
1400
1200
1000
800
600
400
200
0
$40,000,000
$35,000,000
$30,000,000
$25,000,000
$20,000,000
$15,000,000
$10,000,000
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2007
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2021
2022

CASE: UE 416
WITNESS: Bret Stevens

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3302

PGE Audit Report E22-62

August 22, 2023

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WITNESS: Bret Stevens

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3302

PGE Audit Report E22-62

August 22, 2023

Oregon
Kate Brown, Governor

Public Utility Commission
201 High St SE Suite 100
Salem, OR 97301
Mailing Address: PO Box 1088
Salem, OR 97308-1088
Consumer Services
1-800-522-2404
Local: 503-378-6600
Administrative Services
503-373-7394

August 26, 2022

MARIA POPE
PRESIDENT & CEO
PORTLAND GENERAL ELECTRIC
121 SW SALMON STREET
PORTLAND, OR 97204

RE: OPUC Report No. E22-62R, Portland General Electric-Vegetation (Systemwide)

Enclosed is a copy of OPUC Safety Report No. E22-62R, which cites probable violations of the National Electrical Safety Code (NESC) and Oregon Administrative Rule (OAR) 860-024-0016.

OPUC Safety Staff recently performed the annual review of the PGE vegetation management program. This occurred primarily from July 26 to August 22, 2022, in the communities and rural areas listed within the body of the report.

Staff's report identifies locations where contact between vegetation and energized high voltage conductors have been identified. Many trees, although not actively in contact with a conductor, had less than the minimum clearances prescribed by the Administrative Rule. Staff notes these as observations because direct measurement is not possible or feasible during the review.

Staff is optimistic regarding the trim cycle modifications PGE has proposed and adopted which should continue to improve the vegetation management program. The short-term data from Safety Staff audits starting in 2020 indicates the number of tree and energized primary conductor contacts continues to decrease. The instances of "cycle buster" and end of cycle energized conductor tree contacts remains to be a high percentages of tree contacts recorded by Staff. Maintenance of tree-to-conductor clearances, in general, specifically those in High Fire Risk Zones (HFRZ) are not adequate to meet the Oregon Administrative Rule throughout the duration of the trim cycle and should be addressed. A historical graph of readily climbable trees and primary conductor vegetation contacts, including contacts in High Fire Risk Zones (HFRZ) is attached for your reference.

Safety staff noted that tree crew numbers in the field do not seem to reflect the crew numbers quoted during PGE's first quarter meeting of this year and show a decline from the number of crews observed in previous years.

Staff observed **407** locations where evidence existed of contact between vegetation and primary electrical conductors. A limited breakdown of the probable violations follows:

- Nineteen locations are readily climbable trees noted as **hazardous conditions** in Citation A.
- One hundred and eleven locations involve multiple trees contacting the primary conductors.
- Sixteen locations within Citations A and B, were located within a PGE's High Fire Risk Zones (HFRZ). The number of violations identified indicates the company's vegetation management program is not adequately addressing the vegetation/energized conductor contacts in the elevated risk High Fire Risk Zones. (HFRZ).

In response to this report:

1. On or before September 30, 2022, submit documentation confirming correction of the probable violations related to **readily climbable trees**, as well as those listed specifically as **hazardous conditions**.

2. On or before February 27, 2023, submit documentation confirming correction of the remaining probable violations cited in this report.

If a time extension is needed, submit a written request stating the reason(s) for the delay and the proposed schedule to complete the work. If government permits are causing a delay, include the date the permits were applied for, and a permitting agency contact person and telephone number. If you disagree with any cited probable violation, please furnish Staff a letter within 30 days requesting an informal conference.

Each electric supply and telecommunication operator in Oregon, (defined in OAR 860-024-0001(5)), is responsible to construct, operate, and maintain its line facilities in compliance with the NESC. Refer to ORS 757.035 and OARs 860-024-0010 and 860-023-0005 for Oregon laws and rules regarding minimum OPUC safety standards. Particular focus should be given to NESC Rules 090,110 121, 214, 313, and OAR 860-024-0011, which address ongoing inspection and maintenance responsibilities.

Failure to comply with the OPUC safety regulations or NESC rules can result in Commission orders and/or civil penalties. Refer to ORS 757.990(1) for penalty amounts.

If you have any questions regarding this letter or report, please contact me at the number listed below, or Steve Sims at (503) 339-6749 or Alex Chaney at (503) 559-4011. Please reply to OPUC.NESCSafety@state.or.us for report updates, time extensions, or to close the report in the OPUC enforcement log.

Leon Grumbo
Electric Safety Program Manager
Utility Safety Reliability & Security Division
(503) 881-7707
leon.grumbo@state.or.us
OPUC.NESCSafety@state.or.us

Attachments: Report E22-62R
Historical Vegetation Graph

OREGON PUBLIC UTILITY COMMISSION
UTILITY SAFETY REPORT

DATES OF REVIEW:	July 26th to August 22st	REPORT NO.: E22-62R
UTILITY OPERATOR:	Portland General Electric (PGE)	
LOCATION OF REVIEW:	Annual review of vegetation management program at various locations System-Wide.	
OPUC REPRESENTATIVES:	Leon Grumbo, Steve Sims, Alex Chaney	

COVERAGE: It should not be assumed that this review discovered all violations, or that the recommendations, if followed would ensure compliance with the National Electrical Safety Code (NESC). Any included "remarks" or "recommendations" should not be construed as PUC Orders. The reader is referred to the latest edition of the NESC adopted in OAR 860-024-0010 for the minimum safety requirements for electric supply and telecommunication lines.

NOTICE OF PROBABLE VIOLATIONS CITED:

A. Citation:	**Readily climbable tree with inadequate clearance to high voltage conductor.**
Reference:	NESC Rules Number: 012C, 218 and Oregon Administrative Rule 860-024-0016.

All of Salem west of Interstate 5 from Salem to Wilsonville including Salem, St Paul, Donald, Brooks, Grand Ronde, Willamina, Sheridan, Ballston, Amity, Dayton, Lafayette, Carlton, Yamhill, Newberg

	Locations	*Pole Numbers*	*Comments*
1.	On Sunnyview Road NE, Salem (44.9561, -123.0100)	C73-23C 14424	**Multiple readily climbable trees show evidence of contacting the primary conductor.**
2.	In alley behind 1450 Jefferson Street NE, Salem (44.9520, -123.0164)	C73-23A 3363	**Readily climbable tree shows evidence of contacting the primary conductor.**

West of Interstate 5 from Sherwood to the Columbia River including Sherwood, Tualatin, Tigard, Beaverton, Garden Home, Aloha, Farmington, North Plains, Hillsboro, Scappoose, Sauvie Island, St Johns

	Locations	*Pole Numbers*	*Comments*
3.	540 SW Dennis Avenue, Hillsboro (45.5167, -122.9958)	C1301A 494	**Readily climbable tree shows evidence of contacting the primary conductor.**
4.	5870 SW Delker Road, Tualatin (45.3609, -122.7373)	D21-31B 8600	**Readily climbable tree shows evidence of contacting the primary conductor.**
5.	22281 SW 55th Avenue, Tualatin (45.3588, -122.7330)	D21-31B 3271	**Two readily climbable trees show evidence of contacting the primary conductor.**

6.	On SW Schatz Road, Tualatin (45.3574, -122.7312)	D21-31A 3258	**Multiple readily climbable trees show evidence of contacting the primary conductor.**
7.	Across from 7142 SE 302nd Avenue, Gresham (45.4712, -122.3525)	D1419A 39	**Readily climbable tree shows evidence of contacting the primary conductor.**
8.	2879 SE 16th Street, Gresham (45.4855, -122.4037)	D1314A 2515	**Readily climbable tree shows evidence of contacting the primary conductor.**

East of Interstate 5 and west of Interstate 205 from West Linn to the Columbia River including West Linn, Clackamas, Gladstone, Lake Oswego, Milwaukie, Sellwood, SE Portland west of Interstate 205

	Locations	*Pole Numbers*	*Comments*
9.	5017 SE Tolman Street, Portland (45.4771, -122.6109)	D1218C 20	**Readily climbable tree shows evidence of contacting the primary conductor.**
10.	1555 SW Borland Road, West Linn (45.3654, -122.6925)	D21-28C 4059	**Multiple readily climbable trees show evidence of contacting the primary conductor.**
11.	681 SW Borland Road, West Linn (45.3550, -122.6829)	D21-34B 6771	**Readily climbable tree shows evidence of contacting the primary conductor.**
12.	1293 14th Street, West Linn (45.3413, -122.6553)	D31-02B 79	**Readily climbable tree shows evidence of contacting the primary conductor.**

East of Interstate 5 from Turner to South of Canby including Silverton, Mt Angel, Monitor, Gervais, Woodburn, Molalla, Colton, Hubbard, Aurora, Canby, Mulino, Wilsonville

	Locations	*Pole Numbers*	*Comments*
13.	7708 Sunnybrook Lane SE, Salem (44.8437, -122.9042)	C8226C 1468	**Readily climbable tree shows evidence of contacting the primary conductor.**
14.	3790 Fisher Road NE, Salem (44.9739, -122.9884)	C7207C 130 to C7207C 7065	**Multiple spans of readily climbable trees show evidence of contacting the primary conductor.**
15.	4290 45th Ave NE, Salem (44.9813, -122.9730	C7207A 2193	**Readily climbable tree shows evidence of contacting the primary conductor.**
16.	23215 SW Newland Road, Wilsonville (45.3520, -122.7228)	D21-31D 3969	**Readily climbable tree shows evidence of contacting the primary conductor.**

East of I-205, Canby & Estacada to the Columbia River including Oregon City Boring, Sandy, Welches, Happy Valley

	Locations	*Pole Numbers*	*Comments*
17.	On South Haines Road, Canby (45.2723, -122.6610)	D3135B 924	**Readily climbable tree shows evidence of contacting the primary conductor.**
18.	Across from 7142 SE 302nd Avenue, Gresham (45.4712, -122.3525)	D1419A 39	**Readily climbable tree shows evidence of contacting the primary conductor.**
19.	2879 SE 16th Street, Gresham (45.4855, -122.4037)	D1314A 2515	**Readily climbable tree shows evidence of contacting the primary conductor.**

B. Citation:	Trees interfering with or near high voltage conductor.
Reference:	NESC Rules Number: 012C, 218 and Oregon Administrative Rule 860-024-0016.

All of Salem west of Interstate 5 from Salem to Wilsonville including Salem, St Paul, Donald, Brooks, Grand Ronde, Willamina, Sheridan, Ballston, Amity, Dayton, Lafayette, Carlton, Yamhill, Newberg

	Locations	*Pole Numbers*	*Comments*
1.	On Kuebler Blvd. South, Salem (44.8832, -123.0847)	C83-17B 2269	Tree shows evidence of contacting the primary conductor.
2.	On Kuebler Blvd. South, Salem (44.8832, -123.0803)	C83-08D 1285	Tree shows evidence of contacting the primary conductor.
3.	5045 River Road South, Salem (44.8824, -123.1369)	C84-14A 213	Tree shows evidence of contacting the primary conductor.
4.	On River Road South, Salem (44.8799, -123.1387)	C84-14A 162	Tree shows evidence of contacting the primary conductor.
5.	On River Road South, Salem (44.8878, -123.1334)	C84-12C 188	Two trees show evidence of contacting the primary conductor.
6.	4335 River Road South, Salem (44.8931, -123.1304)	C84-12B 98	Two trees show evidence of contacting the primary conductor.
7.	5089 Riverdale Road South, Salem (44.8824, -123.1270)	C84-13B 156	Tree shows evidence of contacting the primary conductor.
8.	On River Road South, Salem (44.9021, -123.1019)	C83-06C 3088	Tree shows evidence of contacting the primary conductor.
9.	On Jackson Hill Road SE, Salem (44.8322, -123.0301)	C83-35B 631	Multiple trees show evidence of contacting the primary conductor.
10.	On Boone Road SE, Salem (44.8823, -123.0458)	C83-15B 2069	Tree shows evidence of contacting the primary conductor.
11.	695 15th Street NE, Salem (44.9426, -123.0196)	C73-23D 4528	Tree shows evidence of contacting the primary conductor.
12.	590 14th Street NE, Salem (44.9415, -123.0217)	C73-23C 4528	Tree shows evidence of contacting the primary conductor.
13.	631 Winter Street NE, Salem (44.9446, -123.0294)	C73-23C 3574	Tree shows evidence of contacting the primary conductor.
14.	1340 Nebraska Avenue NE, Salem (44.9472, -123.0193)	C73-23D 3008	Tree shows evidence of contacting the primary conductor.
15.	On Gibson Road NW, Salem (44.9813, -123.1039)	C73-07B 10253	Multiple trees show evidence of contacting the primary conductor.
16.	On Bruch College Road NW, Salem (45.0125, -123.1292)	C64-36B 73	Tree shows evidence of contacting the primary conductor.
17.	On Spring Valley Road NW, Salem (45.0354, -123.1182)	C64-24A 253	Multiple trees show evidence of contacting the primary conductor.
18.	On Maples Street North, Keizer (45.0137, -123.0621)	C63-28C 269	Tree shows evidence of contacting the primary conductor.
19.	8275 Wheatland Road North, Keizer (45.0389, -123.0177)	C63-23A 152	Tree shows evidence of contacting the primary conductor.
20.	On Donald Road NE, Donald (45.2207, -122.8311)	C41-17D 523	Tree shows evidence of contacting the primary conductor.

21.	On NE Butteville Road, Aurora (45.2890, -122.7934)	C31-22D 123	Tree shows evidence of contacting the primary conductor.
22.	26350 NE Butteville Road, Aurora (45.2859, -122.7729)	C31-26A 707	Multiple trees show evidence of contacting the primary conductor.
23.	On NE Boones Ferry Road, Aurora (45.2868, -122.7751)	C31-26B 742	Tree shows evidence of contacting the primary conductor.
24.	29560 NW Olson Road, Gaston (45.4301, -123.1529)	C24-02B 1616	Tree shows evidence of contacting the primary conductor.
25.	On NW Goodin Creek Road, Gaston (45.4108, -123.1452)	C24-11D 79	Tree shows evidence of contacting the primary conductor. **HFRZ**
26.	1038 Hwy 47, Carlton (45.2872, -123.1748)	C34-27B 513	Tree shows evidence of contacting the primary conductor.
27.	On Willamina Creek Road, Willamina (45.1068, -123.4968)	C57-25C 446	Tree shows evidence of contacting the primary conductor.

West of Interstate 5 from Sherwood to the Columbia River including Sherwood, Tualatin, Tigard, Beaverton, Garden Home, Aloha, Farmington, North Plains, Hillsboro, Scappoose, Sauvie Island, St Johns

	Locations	*Pole Numbers*	*Comments*
28.	On SW Sunset Blvd, Sherwood (45.3499, -122.8314)	C2132D 666	Multiple trees show evidence of contacting the primary conductor.
29.	On SW Beef Bend Road, Portland (45.4018, -122.8299)	C2117A 698	Tree shows evidence of contacting the primary conductor.
30.	630 SW Dennis Avenue, Hillsboro (45.5157, -122.9958)	C1301A 599	Tree shows evidence of contacting the primary conductor.
31.	On SW Tongue Lane, Cornelius (45.4838, -123.0480)	C1315C 74 to C1315C 73	Multiple trees show evidence of contacting the primary conductor.
32.	36260 SW Tongue Lane, Cornelius (45.4838, -123.0498)	C1315C 931	Tree shows evidence of contacting the primary conductor.
33.	32710 SW Tongue Lane, Cornelius (45.4849, -123.0141)	C1314A 106	Multiple trees show evidence of contacting the primary conductor.
34.	On SW Laurelwood Road, Gaston (45.4248, -123.0896)	C2305C 4516	Tree shows evidence of contacting the primary conductor.
35.	46633 NW Sell Road, Banks (45.4849, -123.0141)	B2415A 291	Tree shows evidence of contacting the primary conductor
36.	38760 NW Harrison Road, Banks (45.6216, -123.0760)	B2332A 97	Tree shows evidence of contacting the primary conductor
37.	On NW Hahn Road, Banks (45.6282, -123.0729)	B2328C 307	Tree shows evidence of contacting the primary conductor
38.	On NW Davidson Road, Banks (45.6425, -123.0825)	B2320D 1169	Tree shows evidence of contacting the primary conductor. **HFRZ**
39.	On NW Davidson Road, Banks (45.6463, -123.0835)	B2320A 1173	Tree shows evidence of contacting the primary conductor. **HFRZ**

40.	15327 NW Old Pumpkin Ridge Road, North Plains (45.6314, -123.0113)	B2326A 421	Tree shows evidence of contacting the primary conductor. **HFRZ**
41.	2200 NW Susbauer Road, Cornelius (45.5360, -123.0432)	B1327C 4976	Tree shows evidence of contacting the primary conductor.
42.	3865 Baseline Street, Hillsboro (45.5199, -123.0238)	C1302B 1078 to C1302B 1079	Multiple trees show evidence of contacting the primary conductor.
43.	On SW Tualatin Valley Highway, Hillsboro (45.5199, -123.0166)	C1302A 2760	Tree shows evidence of contacting the primary conductor.
44.	1050 SW Baseline Street, Hillsboro (45.5191, -123.0017)	C1301B 1922	Two trees show evidence of contacting the primary conductor.
45.	On NE 25th Avenue, Hillsboro (45.5438, -122.9575)	B1229A 895 to B1229A 893	Multiple trees show evidence of contacting the primary conductor.
46.	On NE 15th Avenue, Hillsboro (45.5402, -122.9663)	B1229C 502 to B1229B 383	Multiple trees show evidence of contacting the primary conductor.
47.	1485 NE Sunrise Lane, Hillsboro (45.5367, -122.9665)	B1229C 2214	Two trees show evidence of contacting the primary conductor.
48.	1299 NE 17th Avenue, Hillsboro (45.5345, -122.9646)	B1232B 2844	Tree shows evidence of contacting the primary conductor.
49.	1549 NE Jackson School Road, Hillsboro (45.5361, -122.9801)	B1230D 2855	Tree shows evidence of contacting the primary conductor.
50.	895 NE Melinda Court, Hillsboro (45.5389, -122.9755)	B1230D 1514	Tree shows evidence of contacting the primary conductor.
51.	14510 NW Pioneer Road, Beaverton (45.5214, -122.8262)	B1133C 793	Tree shows evidence of contacting the primary conductor.
52.	211 NW Gina Way, Beaverton (45.5216, -122.8878)	B1236C 207	Tree shows evidence of contacting the primary conductor.
53.	1276 NW Perl Way, Beaverton (45.5288, -122.8891)	B1235A 153	Tree shows evidence of contacting the primary conductor.
54.	4065 SE Bentley Street, Hillsboro (45.5123, -122.9410)	C1204C 1244	Tree shows evidence of contacting the primary conductor.
55.	3149 SE Fairview Blvd., Portland (45.5194, -122.7146)	D1105B 139	Tree shows evidence of contacting the primary conductor.
56.	337 SE Kingston Avenue, Portland (45.5208, -122.7069)	A1132D 511	Multiple trees show evidence of contacting the primary conductor.
57.	127 SE Kingston Avenue, Portland (45.5231, -122.7069)	A1132D 49	Tree shows evidence of contacting the primary conductor.

58.	Behind 1264 NW Summit Avenue, Portland (45.5323, -122.7083)	A1132A 98	Multiple trees show evidence of contacting the primary conductor.
59.	2682 NW Cornell Road, Portland (45.5313, -122.7068)	A1132A 105	Multiple trees show evidence of contacting the primary conductor.
60.	2610 NW Cornell Road, Portland (45.5298, -122.7048)	A1132A 190	Tree shows evidence of contacting the primary conductor.
61.	824 NE 18th Avenue, Portland (45.5292, -122.6894)	A1132A3 127	Tree shows evidence of contacting the primary conductor.
62.	2250 NW Kearny Street, Portland (45.5290, -122.6976)	A1133B 170	Multiple trees show evidence of contacting the primary conductor.
63.	2486 NW Kearny Street, Portland (45.5290, -122.7025)	A1133B 19	Tree shows evidence of contacting the primary conductor.
64.	2182 NW Hoyt Street, Portland (45.5269, -122.6964)	A1133B 187	Tree shows evidence of contacting the primary conductor.
65.	1931 NW Flanders Street, Portland (45.5263, -122.6913)	A1133D2 1258	Tree shows evidence of contacting the primary conductor.
66.	2230 NW Glisan Street, Portland (45.5262, -122.6973)	A1133C 41	Tree shows evidence of contacting the primary conductor.
67.	1137 NW 23rd Avenue, Portland (45.5312, -122.6988)	A1133B 300	Tree shows evidence of contacting the primary conductor.
68.	2046 NW Overton Street, Portland (45.5319, -122.6936)	A1133B 238	Tree shows evidence of contacting the primary conductor.
69.	2376 NW Overton Street, Portland (45.5318, -122.7002)	A1133B 27	Tree shows evidence of contacting the primary conductor.
70.	2066 NW Pettygrove Street, Portland (45.5327, -122.6942)	A1133B 234	Multiple trees show evidence of contacting the primary conductor.
71.	2844 NW Raleigh Street, Portland (45.5338, -122.7097)	A1133A 5478	Multiple trees show evidence of contacting the primary conductor.
72.	2926 NW Raleigh Street, Portland (45.5338, -122.7115)	A1133A 403	Tree shows evidence of contacting the primary conductor.
73.	2644 NW Thurman Street, Portland (45.5353, -122.7058)	A1129D 55	Tree shows evidence of contacting the primary conductor.
74.	3139 NW Vaughn Street, Portland (45.5367, -122.7147)	A1129C 15	Tree shows evidence of contacting the primary conductor.
75.	3275 NW 29th Avenue, Portland (45.5464, -122.7111)	A1129A 238	Tree shows evidence of contacting the primary conductor.
76.	4465 NW Yeon Avenue, Portland (45.5545, -122.7329)	A1119D 49	Tree shows evidence of contacting the primary conductor.
77.	3344 NW Industrial Avenue, Portland (45.5412, -122.7166)	A1129B 400	Tree shows evidence of contacting the primary conductor.
78.	6516 SW Barnes Road, Portland (45.5157, -122.7437)	D1106B 3187	Tree shows evidence of contacting the primary conductor.
79.	Intersection of SW Arboretum Circle and West Burnside Road, Portland (45.5191, -122.7227)	D1105B 6141	Tree shows evidence of contacting the primary conductor. **HFRZ**
80.	2981 NW 53rd Drive, Portland (45.5440, -122.7485)	B1125A 426	Tree shows evidence of contacting the primary conductor. **HFRZ**

81.	8221 NW Cresap Lane, Portland (45.5450, -122.7612)	B1125B 2446	Two trees show evidence of contacting the primary conductor. **HFRZ**
82.	Across from 3744 NW Devoto Lane, Portland (45.5503, -122.77080)	B1123D 1467	Tree shows evidence of contacting the primary conductor.
83.	Behind 3756 NW Devoto Lane, Portland (45.5512, -122.7714)	B1123D 1470	Multiple trees show evidence of contacting the primary conductor.
84.	Intersection of NW Wind Ridge Drive and NW Skyline Blvd., Portland (45.5570, -122.7796)	B1123B 2380	Tree shows evidence of contacting the primary conductor.
85.	13941 Northwest Glendoveer Drive, Portland (45.5960, -122.8217)	B1104C 621	Tree shows evidence of contacting the primary conductor. **HFRZ**
86.	11724 Northwest McNamee Road, Portland (45.6075, -122.8352)	B2132D 300	Tree shows evidence of contacting the primary conductor. **HFRZ**
87.	Across from 12615 NW Skyline Blvd., Portland (45.6145, -122.8667)	B2131B 1299	Tree shows evidence of contacting the primary conductor. **HFRZ**
88.	On NW Skyline Blvd., Portland (45.6689, -122.9109)	B2210D 1002	Tree shows evidence of contacting the primary conductor. **HFRZ**
89.	On SW Pfaffle Street, Portland (45.4380, -122.7580)	C1136C 6636	Tree shows evidence of contacting the primary conductor.
90.	Across from 7333 SW Pine Street, Tigard (45.4433, -122.7533)	C1136A 5133	Tree shows evidence of contacting the primary conductor.
91.	7175 SW Florence Lane, Portland (45.4568, -122.7505)	C1125A 1963	Tree shows evidence of contacting the primary conductor.
92.	6571 SW Taylors Ferry Road, Portland (45.4550, -122.7443)	C1125A 1600	Tree shows evidence of contacting the primary conductor.
93.	10112 SW 55th Avenue, Portland (45.4524, -122.7333)	D1130D 3163	Tree shows evidence of contacting the primary conductor.
94.	10430 SW 55th Avenue, Portland (45.4502, -122.7333)	D1130D 3413	Tree shows evidence of contacting the primary conductor.
95.	5741 SW Pasadena Drive, Portland (45.4457, -122.7359)	D1131B 6187	Two trees show evidence of contacting the primary conductor.
96.	10805 SW 63rd Avenue, Portland (45.4476, -122.7421)	D1131B 997	Tree shows evidence of contacting the primary conductor.
97.	Intersection of SW 62nd Drive and SW Huddleson Street, Portland (45.4491, -122.7385)	D1131C 6818	Multiple trees show evidence of contacting the primary conductor.
98.	6220 SW Taylors Ferry Road, Portland (45.4545, -122.7411)	D1130C 5685	Tree shows evidence of contacting the primary conductor.
99.	9529 SW 62nd Drive, Portland (45.4571, -122.7391)	D1130B 2169	Tree shows evidence of contacting the primary conductor.
100.	9423 SW 62nd Drive, Portland (45.4572, -122.7418)	D1130B 7184	Tree shows evidence of contacting the primary conductor.

101.	5301 SW Taylors Ferry Road, Portland (45.4549, -122.7315)	D1130A 1582	Tree shows evidence of contacting the primary conductor.
102.	9711 SW 50th Avenue, Portland (45.4552, -122.7285)	D1130A 1841	Tree shows evidence of contacting the primary conductor.
103.	8803 SW 51st Avenue, Portland (45.4618, -122.7295)	D1130A 67	Tree shows evidence of contacting the primary conductor.
104.	4509 SW Taylors Ferry Road, Portland (45.4548, -122.7232)	D1130A 1007	Tree shows evidence of contacting the primary conductor.
105.	9314 SW 35th Avenue, Portland (45.4584, -122.7133)	D1129B 1491	Tree shows evidence of contacting the primary conductor.
106.	7639 SW Capitol Hill Road, Portland (45.4688, -122.7000)	D1121C 6101	Tree shows evidence of contacting the primary conductor.
107.	2781 SW Troy Street, Portland (45.4684, -122.7058)	D1120D 1974	Tree shows evidence of contacting the primary conductor.
108.	4875 SW Schatz Road, Tualatin (45.3574, -122.7265)	D21-31A 64	Multiple trees show evidence of contacting the primary conductor.
109.	22720 SW Stafford Road, Tualatin (45.3555, -122.7268)	D21-31A 3219	Multiple trees show evidence of contacting the primary conductor.
110.	23662 SW Stafford Road, Tualatin (45.3486, -122.7348)	D21-31C 6540	Tree shows evidence of contacting the primary conductor.
111.	4342 SW Kanan Drive, Portland (45.4821, -122.7220)	D11-17C 1079	Tree shows evidence of contacting the primary conductor.
112.	1737 SW Canby Street, Portland (45.4691, -122.6960)	D11-21B 2616	Tree shows evidence of contacting the primary conductor.
113.	1615 SW Canby Street, Portland (45.4691, -122.6946)	D11-21B 131	Tree shows evidence of contacting the primary conductor.
114.	5565 SW 88TH Avenue, Portland (45.4801, -122.7677)	C1114D 1786	Multiple trees show evidence of contacting the primary conductor.

East of Interstate 5 and west of Interstate 205 from West Linn to the Columbia River including West Linn, Clackamas, Gladstone, Lake Oswego, Milwaukie, Sellwood, SE Portland west of Interstate 205

Locations		*Pole Numbers*	*Comments*
115.	20395 SW Stafford Street, Tualatin (45.3722, -122.7051)	D2129A 6958	Tree shows evidence of contacting the primary conductor.
116.	2249 SW Borland Road, Tualatin (45.3721, -122.6997)	D2128B 3289	Tree shows evidence of contacting the primary conductor.
117.	2175 SW Borland Road, Tualatin (45.3711, -122.6982)	D2128B 6826	Multiple trees show evidence of contacting the primary conductor.
118.	2100 SW Borland Road, Tualatin (45.3691, -122.6972)	D2128B 6987	Tree shows evidence of contacting the primary conductor.
119.	1180 Rosemont Road, West Linn (45.3698, -122.6483)	D2126A 3955	Tree shows evidence of contacting the primary conductor.
120.	18895 Old River Drive, West Linn (45.3943, -122.6403)	D2113C 1152	Tree shows evidence of contacting the primary conductor.
121.	3188 Glenmorrie Drive, Lake Oswego (45.4066, -122.6553)	D2111C 5436	Tree shows evidence of contacting the primary conductor.

122.	Across 2980 Glenmorrie Drive, Lake Oswego (45.4054, -122.6547)	D2111C 5433	Multiple trees show evidence of contacting the primary conductor.
123.	2445 Glenmorrie Drive, Lake Oswego (45.4031, -122.6571)	D2114B 780	Multiple trees show evidence of contacting the primary conductor.
124.	2681 Greentree Road, Lake Oswego (45.4027, -122.7039)	D2117A 5214	Multiple trees show evidence of contacting the primary conductor.
125.	2991 Glen Haven Road, Lake Oswego (45.4021, -122.7073)	D2117A 5129	Tree shows evidence of contacting the primary conductor.
126.	Intersection of Woodside Circle and Deerbrush Avenue, Lake Oswego (45.3962, -122.7218)	D2117C 10364	Tree shows evidence of contacting the primary conductor.
127.	Intersection of SE Emerald Drive and SE Jennings Avenue, Portland (45.3948, -122.6041)	D2218D 2154	Tree shows evidence of contacting the primary conductor.
128.	5323 SE Jennings Avenue, Portland (45.3928, -122.6088)	D2218D 2785	Two trees show evidence of contacting the primary conductor.
129.	4531 SE Jennings Avenue, Portland (45.3905, -122.6158)	D2218C 814	Multiple trees show evidence of contacting the primary conductor.
130.	4215 SE Jennings Avenue, Portland (45.3891, -122.6195)	D2219B 75	Tree shows evidence of contacting the primary conductor.
131.	18535 SE River Road, Portland (45.3884, -122.6146)	D2219B 6	Tree shows evidence of contacting the primary conductor.
132.	5035 SE Glen Echo Avenue, Portland (45.3830, -122.6112)	D2219B 5844	Tree shows evidence of contacting the primary conductor.
133.	4785 SE La Cour Court, Portland (45.3815, -122.6148)	D2219C 958	Tree shows evidence of contacting the primary conductor.
134.	4289 SE Manewal Lane, Portland (45.3823, -122.6188)	D2219B 1695	Tree shows evidence of contacting the primary conductor.
135.	19555 River Road, Portland (45.3806, -122.6069)	D2219D 6618	Multiple trees show evidence of contacting the primary conductor.
136.	19575 River Road, Portland (45.3788, -122.6084)	D2219D 7583	Tree shows evidence of contacting the primary conductor.
137.	17415 SE River Road, Portland (45.3968, -122.6274)	D2113A 4209	Multiple trees show evidence of contacting the primary conductor.
138.	2911 SE Laurelwood Drive, Portland (45.3987, -122.6326)	D2213B 1717	Tree shows evidence of contacting the primary conductor.
139.	2850 SE Cooke Road, Portland (45.3993, -122.6338)	D2113B 733	Tree shows evidence of contacting the primary conductor.
140.	2762 SE Vineyard Way, Portland (45.4007, -122.6346)	D2113B 2085	Multiple trees show evidence of contacting the primary conductor.
141.	Intersection of SE River Road and SE Vineyard Way, Portland (45.4011, -122.6334)	D2213B 2087	Multiple trees show evidence of contacting the primary conductor.
142.	2420 SE Mulberry Drive, Portland (45.4008, -122.6380)	D2113B 6402	Tree shows evidence of contacting the primary conductor.
143.	2611 SE Tarbell Avenue, Portland (45.4047, -122.6371)	D2112C 2206	Multiple trees show evidence of contacting the primary conductor.

144.	16205 SE River Road, Portland (45.4056, -122.6405)	D2112C 1514	Multiple trees show evidence of contacting the primary conductor.
145.	15695 SE Dana Avenue, Portland (45.4093, -122.6489)	D2111D 2462	Tree shows evidence of contacting the primary conductor.
146.	14325 SE River Road, Portland (45.4188, -122.6457)	D2102D 2222	Tree shows evidence of contacting the primary conductor.
147.	16417 SE McLoughlin Blvd., Portland (45.4039, -122.6229)	D2112D 763	Tree shows evidence of contacting the primary conductor.
148.	15117 SE McLoughlin Blvd., Portland (45.4135, -122.6303)	D2112A 2645	Tree shows evidence of contacting the primary conductor.
149.	14585 SE McLoughlin Blvd., Portland (45.4176, -122.6328)	D2112B 937	Multiple trees show evidence of contacting the primary conductor.
150.	2096 SE Pinelane Street, Portland (45.4195, -122.6418)	D2102D 3943	Tree shows evidence of contacting the primary conductor.
151.	15716 SE Creswain Avenue, Portland (45.4094, -122.6400)	D2112C 7207	Tree shows evidence of contacting the primary conductor.
152.	2340 SE Swain Avenue, Portland (45.4073, -122.6402)	D2112C 921	Tree shows evidence of contacting the primary conductor.
153.	16217 SE River Road, Portland (45.4053, -122.6399)	D2112C 377	Tree shows evidence of contacting the primary conductor.
154.	2710 SE Concord Road, Portland (45.4063, -122.6349)	D2112C 4497	Tree shows evidence of contacting the primary conductor.
155.	2800 SE Concord Road, Portland (45.4067, -122.6336)	D2112C 2826	Tree shows evidence of contacting the primary conductor.
156.	3310 SE Westview Road, Portland (45.4060, -122.6283)	D2112D 10952	Tree shows evidence of contacting the primary conductor.
157.	15103 SE Kellogg Avenue, Portland (45.4137, -122.6286)	D2112A 2234	Tree shows evidence of contacting the primary conductor.
158.	15016 SE Oatfield Road, Portland (45.4141, -122.6242)	D2112A 4356	Tree shows evidence of contacting the primary conductor.
159.	4404 SE Hill Road, Portland (45.4189, -122.6173)	D2206C 1329	Two trees show evidence of contacting the primary conductor.
160.	4912 SE Hill Road, Portland (45.4189, -122.6124)	D2206C 1796	Tree shows evidence of contacting the primary conductor.
161.	Across from 5201 SE Hill Road, Portland (45.4170, -122.6097)	D2207A 842	Tree shows evidence of contacting the primary conductor.
162.	15318 SE Outfield Road, Portland (45.4117, -122.6217)	D2112A 3649	Tree shows evidence of contacting the primary conductor.
163.	3950 SE View Acres Road, Portland (45.4131, -122.6216)	D2112A 2638	Multiple trees show evidence of contacting the primary conductor.
164.	4550 SE View Acres Road, Portland (45.4163, -122.6171)	D2207B 2812	Tree shows evidence of contacting the primary conductor.
165.	4818 SE View Acres Road, Portland (45.4189, -122.6133)	D2206C 2470	Multiple trees show evidence of contacting the primary conductor.

166.	Across from 5904 SE Thiessen Road, Portland (45.4162, -122.6022)	D2207A 2802	Multiple trees show evidence of contacting the primary conductor.
167.	Intersection of SE Aldercrest Road and SE Thiessen Road, Portland (45.4163, -122.6000)	D2207A 2832	Tree shows evidence of contacting the primary conductor.
168.	6050 SE Alderhill Loop, Portland (45.4171, -122.6004)	D2208B 2844	Tree shows evidence of contacting the primary conductor.
169.	6593 SE Thiessen Road, Portland (45.4162, -122.5962)	D2208B 3303	Tree shows evidence of contacting the primary conductor.
170.	16060 SE Brenda Avenue, Portland (45.4066, -122.5849)	D2208D 3879	Multiple trees show evidence of contacting the primary conductor.
171.	16704 SE Oatfield Road, Portland (45.4024, -122.6092)	D2218A 1084	Multiple trees show evidence of contacting the primary conductor.
172.	15106 SE Oatfield Road, Portland (45.4138, -122.6239)	D2112A 561	Tree shows evidence of contacting the primary conductor.
173.	14928 SE Oatfield Road, Portland (45.4146, -122.6248)	D2112A 2306	Tree shows evidence of contacting the primary conductor.
174.	13001 SE Rusk Road, Portland (45.4289, -122.6014)	D2206A 10438	Tree shows evidence of contacting the primary conductor.
175.	7919 SE Sunnyside Drive, Portland (45.4337, -122.5807)	D1232D 6616	Multiple trees show evidence of contacting the primary conductor.
176.	7506 SE Sunnyside Drive, Portland (45.4333, -122.5865)	D1232D 4389	Tree shows evidence of contacting the primary conductor.
177.	12145 SE 80th Avenue, Portland (45.4353, -122.5807)	D1232D 4204	Tree shows evidence of contacting the primary conductor.
178.	7816 SE Stephanie Court, Portland (45.4379, -122.5838)	D1232D 12224	Tree shows evidence of contacting the primary conductor.
179.	11802 SE Fuller Road, Portland (45.4363, -122.5850)	D1232D 44	Multiple trees show evidence of contacting the primary conductor.
180.	8010 SE McBride Street, Portland (45.4358, -122.5814)	D1232D 4963	Tree shows evidence of contacting the primary conductor.
181.	11430 SE Fuller Road, Portland (45.4397, -122.5828)	D1232D 11749	Multiple trees show evidence of contacting the primary conductor.
182.	11200 SE Fuller Road, Portland (45.4418, -122.5817)	D1232A 4563	Multiple trees show evidence of contacting the primary conductor.
183.	Across from 11101 SE Fuller Road, Portland (45.4426, -122.5813)	D1232A 3696	Two trees show evidence of contacting the primary conductor.
184.	10920 SE 72nd Avenue, Portland (45.4438, -122.5893)	D1232A 8008	Tree shows evidence of contacting the primary conductor.
185.	10852 SE 7nd Avenue, Portland (45.4446, -122.5891)	D1232A 8006	Multiple trees show evidence of contacting the primary conductor.
186.	7411 SE Monroe Street, Portland (45.4448, -122.5870)	D1232A 8446	Tree shows evidence of contacting the primary conductor.
187.	6710 SE Catalina Lane, Portland (45.4426 ,-122.5941)	D1232B 3280	Tree shows evidence of contacting the primary conductor.

188.	6625 SE Charles Street, Portland (45.4419, -122.5955)	D1232B 6368	Tree shows evidence of contacting the primary conductor.
189.	7245 SE Harmony Drive, Portland (45.4411, -122.5883)	D1232A 3679	Tree shows evidence of contacting the primary conductor.
190.	7643 SE Harmony Drive, Portland (45.4411, -122.5844)	D1232A 3674	Tree shows evidence of contacting the primary conductor.
191.	6306 SE Cedarcrest Drive, Portland (45.4329, -122.5983)	D1232C 8723	Tree shows evidence of contacting the primary conductor.
192.	Intersection of SE Railroad Avenue and SE Harmony Road, Portland (45.4324, -122.5997)	D1232C 8724	Multiple trees show evidence of contacting the primary conductor.
193.	11415 SE Stanley Avenue, Portland (45.4403, -122.6037)	D1231A 1456	Tree shows evidence of contacting the primary conductor.
194.	On SE Railroad Avenue, Portland (45.4362, -122.6096) to (45.4430 -122.6236)	D1231D 8807 to D1136A 71	Multiple spans show evidence of multiple trees contacting the primary conductor.
195.	5411 SE Monroe Street, Portland (45.4448, -122.6076)	D1231A 4110	Tree shows evidence of contacting the primary conductor.
196.	4786 SE Jackson Street, Portland (45.4458, -122.6135)	D1231B 2961	Tree shows evidence of contacting the primary conductor.
197.	3902 SE King Street, Portland (45.4480, -122.6229)	D1125D 47	Tree shows evidence of contacting the primary conductor.
198.	10264 SE 37th Avenue, Portland (45.4491, -122.6247)	D1125D 4665	Multiple trees show evidence of contacting the primary conductor.
199.	9922 SE 37th Avenue, Portland (45.4511, -122.6247)	D1125D 4209	Two trees show evidence of contacting the primary conductor.
200.	4180 SE Harvey Court, Portland (45.4513, -122.6205)	D1125D 2057	Tree shows evidence of contacting the primary conductor.
201.	4016 SE Rosewell Street, Portland (45.4584, -122.6220)	D1125A 6791	Tree shows evidence of contacting the primary conductor.
202.	8607 SE 29th Avenue, Portland (45.4605, -122.6330)	D1125B 3397	Multiple trees show evidence of contacting the primary conductor.
203.	8607 SE 29th Avenue, Portland (45.4573, -122.6328)	D1125B 2783	Tree shows evidence of contacting the primary conductor.
204.	9029 SE 29th Avenue, Portland (45.4552, -122.6327)	D1125B 5514	Multiple trees show evidence of contacting the primary conductor.
205.	9323 SE 29th Avenue, Portland (45.4529, -122.6327)	D1125C 3590	Tree shows evidence of contacting the primary conductor.
206.	5707 SE 92nd Avenue, Portland (45.4813, -122.5692)	D1216C 209	Tree shows evidence of contacting the primary conductor.
207.	8940 SE Reedway Street, Portland (45.4813, -122.5703)	D1216C 211	Multiple trees show evidence of contacting the primary conductor.
208.	3223 SE 92nd Avenue, Portland (45.4988, -122.5684)	D1209A 3161	Multiple trees show evidence of contacting the primary conductor.
209.	2626 SE 92nd Avenue, Portland (45.5031, -122.5685)	D1209A 3173	Tree shows evidence of contacting the primary conductor.

210.	Across from 4035 SE 82nd Avenue, Portland (45.4933, -122.5787)	D1209C 985	Tree shows evidence of contacting the primary conductor.
211.	Across from 8230 SE Liebe Steet, Portland (45.4870, -122.5782)	D1216B 28	Multiple trees show evidence of contacting the primary conductor.
212.	Intersection of SE Liebe Street and SE 86th Court, Portland (45.4870, -122.5741)	D1216B 103	Tree shows evidence of contacting the primary conductor.
213.	Intersection of SE Raymond Court and Southeast 86TH Court, Portland (45.4858, -122.5741)	D1216B 197	Tree shows evidence of contacting the primary conductor.
214.	7123 SE Knight Street, Portland (45.4803, -122.5898)	D1217C 95	Tree shows evidence of contacting the primary conductor.
215.	7005 SE Mitchell Street, Portland (45.4857, -122.5912)	D1217B 95	Tree shows evidence of contacting the primary conductor.
216.	5905 SE Insley Street, Portland (45.4840, -122.6028)	D1218A 26	Tree shows evidence of contacting the primary conductor.
217.	5519 SE Insley Street, Portland (45.4839, -122.6061)	D1218A 195	Tree shows evidence of contacting the primary conductor.
218.	Behind 5218 SE Tolman Street, Portland (45.4770, -122.6078)	D1216D 264	Multiple trees show evidence of contacting the primary conductor.
219.	6232 SE 47th Avenue, Portland (45.4771, -122.6143)	D1218C 321	Tree shows evidence of contacting the primary conductor.
220.	6136 SE 46th Avenue, Portland (45.4778, -122.6153)	D1218C 108	Tree shows evidence of contacting the primary conductor.
221.	3808 SE Henry Street, Portland (45.4762, -122.6233)	D1113D 77	Tree shows evidence of contacting the primary conductor.
222.	6025 SE 34th Avenue, Portland (45.4789 -122.6283)	D1113D 110	Multiple trees show evidence of contacting the primary conductor.
223.	3817 SE Tolman Street, Portland (45.4771, -122.6232)	D1113D 15	Tree shows evidence of contacting the primary conductor.
224.	5835 SE 40th Avenue, Portland (45.4800, -122.6221)	D1113D 236	Tree shows evidence of contacting the primary conductor.
225.	5730 SE 41st Avenue, Portland (45.4807, -122.6204)	D1113D 308	Tree shows evidence of contacting the primary conductor.
226.	4205 SE Romana Street, Portland (45.4807, -122.6194)	D1218C 179	Tree shows evidence of contacting the primary conductor.
227.	4507 SE Romana Street, Portland (45.4807, -122.6163)	D1218C 246	Multiple trees show evidence of contacting the primary conductor.
228.	Across from 5609 SE 48th Avenue, Portland (45.4818, -122.6133)	D1218C 60	Tree shows evidence of contacting the primary conductor.
229.	5637 SE 45th Avenue, Portland (45.4814, -122.6167)	D1218C 414	Tree shows evidence of contacting the primary conductor.
230.	5233 SE 38th Avenue, Portland (45.4848, -122.6232)	D1113A 49	Tree shows evidence of contacting the primary conductor.

231.	4814 SE 28th Avenue, Portland (45.4881, -122.6375)	D1113B 8	Multiple trees show evidence of contacting the primary conductor.
232.	6040 SE 32nd Avenue, Portland (45.4787, -122.6304)	D1113D 229	Multiple trees show evidence of contacting the primary conductor.
233.	6121 SE 32nd Avenue, Portland (45.4780, -122.6311)	D1113C 36	Multiple trees show evidence of contacting the primary conductor.
234.	On SW Ek Road, West Linn (45.3670, -122.7054)	D21-29A 3246	Tree shows evidence of contacting the primary conductor.
235.	797 SW Borland Road, West Linn (45.3556, -122.6847)	D21-13A 6556	Tree shows evidence of contacting the primary conductor.
236.	2665 SW Schaeffer Road, West Linn (45.3492, -122.7041)	D21-32D 3770	Tree shows evidence of contacting the primary conductor.
237.	On SW Turner Road, West Linn (45.3592, -122.6954)	D21-33B 6774	Tree shows evidence of contacting the primary conductor.
238.	On SW Turner Road, West Linn (45.3586, -122.6936)	D21-33B 3215	Two trees show evidence of contacting the primary conductor.
239.	1085 SW Willamette Falls Drive, West Linn (45.3445, -122.6678)	D31-03A 11	Tree shows evidence of contacting the primary conductor.
240.	1208 SW Willamette Falls Drive, West Linn (45.3439, -122.6651)	D31-03A 803	Two trees show evidence of contacting the primary conductor.
241.	On Dollar Street, West Linn (45.3447, -122.6589)	D31-02B 778	Two trees show evidence of contacting the primary conductor.
242.	On Dollar Street, West Linn (45.3451, -122.6603)	D31-02B 75	Tree shows evidence of contacting the primary conductor.
243.	1315 Dollar Street, West Linn (45.3460, -122.6630)	D31-03A 792	Tree shows evidence of contacting the primary conductor.
244.	On Volpp Street, West Linn (45.3393, -122.6502)	D31-02A 5	Multiple trees show evidence of contacting the primary conductor.
245.	On 4th Avenue, West Linn (45.3456, -122.6396)	D31-01B 868	Two trees show evidence of contacting the primary conductor.
246.	On 5th Avenue, West Linn (45.3451, -122.6470)	D31-02A 822	Tree shows evidence of contacting the primary conductor.
247.	On 11th Street, West Linn (45.3431, -122.6519)	D31-02B 1157	Tree shows evidence of contacting the primary conductor.

East of Interstate 5 from Turner to South of Canby including Silverton, Mt Angel, Monitor, Gervais, Woodburn, Molalla, Colton, Hubbard, Aurora, Canby, Mulino, Wilsonville

	Locations	*Pole Numbers*	*Comments*
248.	2266 Cloverdale Drive SE, Jefferson (44.8233, -123.0150)	C9302A 113	Tree shows evidence of contacting the primary conductor.
249.	7715 5th Street SE, Turner (44.8434, -122.9560)	C8229D 298	Tree shows evidence of contacting the primary conductor.
250.	5335 Chicago Street SE, Turner (44.8427, -122.9507)	C8229D 254	Tree shows evidence of contacting the primary conductor.
251.	5255 Boise Street SE, Turner (44.8436, -122.9522)	C8229D 242	Tree shows evidence of contacting the primary conductor.
252.	6724 Mill Creek Road SE, Turner (44.8387, -122.9233)	C8234B 21	Tree shows evidence of contacting the primary conductor.

253.	7937 Pine Tree Lane SE, Turner (44.8398, -122.9309)	C8228D 1755	Multiple trees show evidence of contacting the primary conductor.
254.	7838 Pine Tree Lane SE, Turner (44.8409, -122.9293)	C8228D 2	Multiple trees show evidence of contacting the primary conductor.
255.	7472 Mill Creek Road SE, Aumsville (44.8389, -122.9069)	C8227D 885	Tree shows evidence of contacting the primary conductor.
256.	7632 Witzel Road SE, Turner (44.8450, -122.9399)	C8228C 320	Multiple trees show evidence of contacting the primary conductor.
257.	Intersection of Chrisman Lane SE and Gath Road SE, Salem (44.8726, -122.9530)	C8217D 2818	Tree shows evidence of contacting the primary conductor.
258.	1128 Lancaster Drive NE, Salem (44.9439, -122.9833)	C7219C 2132	Tree shows evidence of contacting the primary conductor.
259.	3925 Lancaster Drive NE, Salem (44.9762, -122.9836)	C7207C 4275	Multiple trees show evidence of contacting the primary conductor.
260.	4579 Lancaster Drive NE, Salem (44.9872, -122.9833)	C7206C 3572	Multiple trees show evidence of contacting the primary conductor.
261.	117 Bayview Way NE, Salem (44.9281, -122.9674)	C7229C 3137	Tree shows evidence of contacting the primary conductor.
262.	Intersection of Center Street NE and Cordon Road NE, Salem 44.9395, -122.9598)	C7229B 665	Tree shows evidence of contacting the primary conductor.
263.	4507 Blackberry Lane NE, Salem (44.9733, -122.9731)	C7207D 123	Tree shows evidence of contacting the primary conductor.
264.	Intersection of Herrin Road NE and 45th Avenue NE, Salem (44.9771, -122.9731)	C7207A 726	Tree shows evidence of contacting the primary conductor.
265.	4582 Herrin Road NE, Salem (44.9771, -122.9709)	C7207A 335	Two trees show evidence of contacting the primary conductor.
266.	4128 Cordon Road NE, Salem (44.9789, -122.9567)	C7208A 1407	Tree shows evidence of contacting the primary conductor.
267.	4410 Cordon Road NE, Salem (44.9854, -122.9552)	C7205D 1203	Tree shows evidence of contacting the primary conductor.
268.	3507 Middle Grove Drive NE, Salem (44.9703, – 122.9616)	C7208C 1385	Tree shows evidence of contacting the primary conductor.
269.	8712 Boulder Ridge Court, Salem (44.9257, -122.8842)	C7236B 20	Tree shows evidence of contacting the primary conductor.
270.	1291 62nd Avenue SE, Salem (44.9137, -122.9339)	C7233D 1921	Tree shows evidence of contacting the primary conductor.
271.	7373 Conifer Road NE, Salem 44.9458, -122.9103)	C7222D 3798	Tree shows evidence of contacting the primary conductor.
272.	6903 Sunnyview Road NE, Salem (44.9565, -122.9205)	C7215C 1563	Tree shows evidence of contacting the primary conductor.
273.	Across 10844 Kaufman Road NE, Silverton (44.9697, -122.8388)	C7108C 379	Tree shows evidence of contacting the primary conductor.
274.	110 Smith Street, Silverton (44.9965, -122.7760)	C7102B 7	Two trees show evidence of contacting the primary conductor.

275.	840 Barger Street, Silverton (44.9973, -122.7788)	C7102B 24	Two trees show evidence of contacting the primary conductor.
276.	6043 Sunnyview Road NE, Salem (44.9549, -122.9372)	C7221A 561	Tree shows evidence of contacting the primary conductor.
277.	15010 South Maple Grove Road, Molalla (45.0411, -122.5579)	D6222B 619	Tree shows evidence of contacting the primary conductor. **HFRZ**
278.	11151 South Wildcat Road, Molalla (45.0783, -122.6367)	D6101B 694	Tree shows evidence of contacting the primary conductor. **HFRZ**
279.	4783 38th Avenue NE, Salem (44.9926, -122.9864)	C7206B 1261	Tree shows evidence of contacting the primary conductor.
280.	4565 Hazelgreen Road NE, Salem (45.0046, -122.9677)	C6232C 910	Tree shows evidence of contacting the primary conductor.
281.	4753 Hazelgreen Road NE, Salem (45.0046, -122.9637)	C6232C 1504	Tree shows evidence of contacting the primary conductor.
282.	5790 Lake Labish Road, Salem (45.0057, -122.9617)	C6232C 1507	Tree shows evidence of contacting the primary conductor.
283.	5995 Lake Labish Road, Salem (45.0078, -122.9617)	C6232B 1511	Tree shows evidence of contacting the primary conductor.
284.	7215 Lakeside Drive NE, Salem (45.0231, -122.9612)	C6229B 952	Tree shows evidence of contacting the primary conductor.
285.	7256 Lakeside Drive NE, Salem (45.0236, -122.9573)	C6229A 2094	Tree shows evidence of contacting the primary conductor.
286.	7296 Lakeside Drive NE, Salem (45.0243, -122.9513)	C6229A 1670	Tree shows evidence of contacting the primary conductor.
287.	4267 Scott Avenue NE, Salem (45.0202, -122.9734)	C6230D 210	Tree shows evidence of contacting the primary conductor.
288.	4433 Dover Avenue NE, Salem (45.0185, -122.9718)	C6230D 219	Two trees show evidence of contacting the primary conductor.
289.	4251 Webb Avenue NE, Salem (45.0177, -122.9753)	C6230D 127	Tree shows evidence of contacting the primary conductor.
290.	Across from 6060 Brooklake Road NE, Salem (45.0417, -122.9362)	C6221A 1608	Two trees in an orchard, **creating a hazard**, show evidence of contacting the primary conductor.
291.	6361 Brooklake Road NE, Salem (45.0402, -122.9309)	C6221A 755	Tree shows evidence of contacting the primary conductor.
292.	6601 Brooklake Road NE, Salem (45.0387, -122.9256)	C6222B 539	Tree shows evidence of contacting the primary conductor.
293.	8646 Lakeside Drive NE, Salem (45.0427, -122.9313)	C6216D 1174	Tree shows evidence of contacting the primary conductor.
294.	Across from 9952 Nusom Road, NE, Salem (45.0344, -122.8566)	C6119C 3766	Tree shows evidence of contacting the primary conductor.
295.	990 Taylor Street, Mount Angel (45.0689, -122.7883)	C6110A 681	Tree shows evidence of contacting the primary conductor.
296.	110 Lincoln Street, Mount Angel (45.0677, -122.8022)	C6110B 518	Tree shows evidence of contacting the primary conductor.

297.	Across 9344 Mount Angel/Gervais Road, Gervais (45.0932, -122.8710)	C5236A 740	Tree shows evidence of contacting the primary conductor.
298.	599 South Settlemier Avenue, Woodburn (45.1386, -122.8640)	C5118B 756	Tree shows evidence of contacting the primary conductor.
299.	583 West Hayes Street, Woodburn (45.1451 -122.8596)	C5107C 310	Two trees show evidence of contacting the primary conductor.
300.	3635 5th Street, Hubbard (45.1839, -122.8087)	C4133A 1118	Tree shows evidence of contacting the primary conductor.
301.	19598 Pacific Highway East, Aurora (45.2028, -122.7791)	C4123C 1716	Tree shows evidence of contacting the primary conductor.
302.	20337 Pacific Highway East, Aurora (45.2133, -122.7700)	C4123A 505	Tree shows evidence of contacting the primary conductor.
303.	25393 Pacific Highway East, Aurora (45.2392, -122.7370)	D4107B 1081	Two trees show evidence of contacting the primary conductor.
304.	531 Doud Street, Woodburn (45.1427, -122.8535)	C5118A 607	Tree shows evidence of contacting the primary conductor.
305.	765 South Pacific Highway, Woodburn (45.1290, -122.8526)	C5119A 2462	Tree shows evidence of contacting the primary conductor.
306.	1050 South Pacific Highway, Woodburn (45.1235, -122.8557)	C5119A 3131	Tree shows evidence of contacting the primary conductor.
307.	6098 Topaz Street NE, Salem (45.0620, -122.9364)	C6209D 977	Two trees show evidence of contacting the primary conductor.
308.	6198 Topaz Street NE, Salem (45.0597 -122.9340)	C6209D 1640	Multiple trees show evidence of contacting the primary conductor.
309.	4375 Turner Road South, Salem (44.8901, -122.9854)	C8207B 1666	Tree shows evidence of contacting the primary conductor.
310.	14985 Woodburn/Monitor Road NE, Woodburn (45.1021, -122.7528)	C5125D 1832	Tree shows evidence of contacting the primary conductor.
311.	14779 South Vaughan Road, Molalla (45.1596, -122.5639)	D5204D 1884	Tree shows evidence of contacting the primary conductor.
312.	30330 South Molalla Avenue, Molalla (45.1678, -122.5757)	D5204B 22	Tree shows evidence of contacting the primary conductor.
313.	30286 South Molalla Avenue, Molalla (45.1690, -122.5753)	D5204B 2488	Multiple trees show evidence of contacting the primary conductor.
314.	14551 South Macksburg Road, Molalla (45.1797, -122.5637)	D4233D 465	Tree shows evidence of contacting the primary conductor.
315.	On South Macksburg Road, Molalla (45.1765, -122.5582)	D4234C 1330	Tree shows evidence of contacting the primary conductor.
316.	15143 South Macksburg Road, Molalla (45.1660, -122.5473)	D5203A 2675	Tree shows evidence of contacting the primary conductor.
317.	17355 South Hallbacka Lane, Mulino (45.1732, -122.5111)	D4236C 1972	Tree shows evidence of contacting the primary conductor.

318.	On South Monroe Lane, Mulino (45.1740 -122.5163)	D4236C 1743	Tree shows evidence of contacting the primary conductor.
319.	Across from 25949 South Hillockburn Road, Estacada (45.2303, -122.3247)	D4409C 158	Tree shows evidence of contacting the primary conductor. **HFRZ**
320.	Across from 28383 South Baurer Road, Colton (45.1949, -122.4144)	D4326B 292	Tree shows evidence of contacting the primary conductor.
321.	On Woodburn/Estacada Highway, Colton (45.1700, -122.4598)	D5305A 4932	Tree shows evidence of contacting the primary conductor.
322.	29444 South Salo Road, Mulino (45.1799, -122.5229)	D4235A 325	Tree shows evidence of contacting the primary conductor.
323.	Across from 28631 South Salo Road, Mulino (45.1934, -122.5278)	D4226D 826	Tree shows evidence of contacting the primary conductor.
324.	15704 South Windy City Road, Mulino (45.1941, -122.5416)	D4227D 2947	Tree shows evidence of contacting the primary conductor.
325.	28605 South Marshal Road, Mulino (45.1934 -122.5435)	D4227D 80	Tree shows evidence of contacting the primary conductor.
326.	29264 South Marshal Road, Mulino (45.1829, -122.5426)	D4234A 8	Tree shows evidence of contacting the primary conductor.
327.	On SW Newland Road, Wilsonville (45.3507, -122.7227)	D21-31D 2410	Tree shows evidence of contacting the primary conductor.
328.	23939 SW Gage Road, Wilsonville (45.3472, -122.7305)	D21-31D 32	Tree shows evidence of contacting the primary conductor.

East of I-205, Canby & Estacada to the Columbia River including Oregon City Boring, Sandy, Welches, Happy Valley

Locations		*Pole Numbers*	*Comments*
329.	23300 South Blount Road, Canby (45.2693, -122.6557)	D3135B 7	Multiple trees show evidence of contacting the primary conductor. Tree wire.
330.	Intersection Of South Bremer Road and South Haines Road, Canby (45.2711, -122.6613)	D3134A 517	Tree shows evidence of contacting the primary conductor.
331.	10730 South Beutel Road, Oregon City (45.3272, -122.6482)	D3111A 4311	Tree shows evidence of contacting the primary conductor.
332.	507 3rd Street, Oregon City (45.3537, -122.6087)	D2231A 7215	Tree shows evidence of contacting the primary conductor.
333.	15275 South Maplelane Road, Oregon City (45.3382, -122.553)	D3203B 172	Tree shows evidence of contacting the primary conductor.
334.	15199 South Maplelane Road, Oregon City (45.3378, -122.5545)	D3203C 18	Tree shows evidence of contacting the primary conductor.

335.	On South Maplelane Road, Oregon City (45.3371, -122.5619)	D3204D 165	Two trees show evidence of contacting the primary conductor.
336.	15107 Thayer Road, Oregon City (45.3312, -122.5569)	D3203C 658	Two trees show evidence of contacting the primary conductor.
337.	On South Lower Highland Road, Beaver Creek (45.2621, -122.5014)	D3236D 2803	Tree shows evidence of contacting the primary conductor.
338.	15618 South Carus Road, Oregon City (45.2714, -122.5469)	D3234A 688	Tree shows evidence of contacting the primary conductor.
339.	16747 South Hattan Road, Oregon City (45.3628, -122.4916)	D2330C 539	Tree shows evidence of contacting the primary conductor. **HFRZ**
340.	15908 South Springwater Road, Oregon City (45.3753, -122.4744)	D2320C 975	Tree shows evidence of contacting the primary conductor.
341.	On South Springwater Road, Oregon City (45.3700, -122.4716)	D2329B 954	Two trees show evidence of contacting the primary conductor.
342.	16268 South Babler Road, Oregon City (45.3710, -122.4539)	D2328B 1597	Tree shows evidence of contacting the primary conductor.
343.	On South Gerber Road, Oregon City (45.3737, -122.4433)	D2328A 974	Two trees show evidence of contacting the primary conductor. **HFRZ**
344.	13300 SE Hubbard Road, Clackamas (45.4140, -122.5274)	D2211A 1	Multiple trees show evidence of contacting the primary conductor.
345.	13780 SE Bluff, Sandy (45.4238, -122.2742)	D2402D 1196	Tree shows evidence of contacting the primary conductor.
346.	On SE Hudson Road, Boring (45.4435, -122.2744)	D1435A 2191 To D1435A 2192	Two trees show evidence of contacting the primary conductor.
347.	On SE Littlepage Road, Corbett (45.5083, -122.2857)	D1402C 250	Tree shows evidence of contacting the primary conductor. Tree Wire.
348.	On US-30 Historic, Troutdale (45.5189, -122.3367)	D1405A 1824	Tree shows evidence of contacting the primary conductor.
349.	3514 SE 317th Avenue, Troutdale (45.4976, -122.3367)	D1408A 1335	Tree shows evidence of contacting the primary conductor.
350.	3768 SE 317th Avenue, Troutdale (45.4956, -122.3367)	D1408D 142	Two trees show evidence of contacting the primary conductor.
351.	On SE Victory Road, Troutdale (45.4938, -122.3364)	D1408D 146	Tree shows evidence of contacting the primary conductor.
352.	On SE Lusted Road, Gresham (45.4759, -122.3323)	D1420A 1624	Multiple trees show evidence of contacting the primary conductor.
353.	On SE Dodge Park Blvd, Gresham (45.4705, -122.3475)	D1420B 236	Tree shows evidence of contacting the primary conductor.

354.	Intersection Of SE Dodge Park Blvd and SE 302nd Avenue, Gresham (45.4708, -122.3528)	D1419A 244 To D1419A 253	Multiple trees show evidence of contacting the primary conductor.
355.	On SE Jackson Road, Gresham (45.4739, -122.3493)	D1420B 502	Tree shows evidence of contacting the primary conductor.
356.	30945 SE Jackson Road, Gresham (45.4739, -122.3451)	D1420B 507	Multiple trees show evidence of contacting the primary conductor.
357.	30830 SE Bluff, Gresham (45.4652, -122.3451)	D1420C 1263	Multiple trees show evidence of contacting the primary conductor.
358.	34727 SE Compton Road, Boring (45.4327, -122.3059)	D1434C 1659	Tree shows evidence of contacting the primary conductor.
359.	33755 SE Compton Road, Boring (45.4327, -122.3154)	D1433D 1667	Tree shows evidence of contacting the primary conductor.
360.	33685 SE Compton Road, Boring (45.4327, -122.3164)	D1433D 1668	Tree shows evidence of contacting the primary conductor.
361.	33685 SE Compton Road, Boring (45.4327, -122.3272)	D1433C 1677 To D1433C 1679	Multiple trees show evidence of contacting the primary conductor.
362.	11422 SE Revenue Road, Boring (45.4411, -122.3315)	D1433B 1566	Multiple trees show evidence of contacting the primary conductor.
363.	10905 SE Revenue Road, Boring (45.4438, -122.3322)	D1432A 1052	Two trees show evidence of contacting the primary conductor.
364.	8444 SE Orient Drive, Gresham (45.462, -122.3486)	D1420C 1114	Tree shows evidence of contacting the primary conductor.
365.	Across from 8801 SE 307th Avenue, Boring (45.4591, -122.3471)	D1429B 975	Tree shows evidence of contacting the primary conductor.
366.	1265 SE Roberts Avenue, Gresham (45.4872, -122.4203)	D1315A 2595	Tree shows evidence of contacting the primary conductor.
367.	On NE Glisan Street, Portland (45.5263, -122.5283)	A1235C 4513	Multiple trees show evidence of contacting the primary conductor.
368.	12155 SE Harold Street, Portland (45.4833, -122.5383)	D1215A 50	Tree shows evidence of contacting the primary conductor.
369.	6625 SE 182nd Avenue, Gresham (45.4745, -122.4757)	D1319A 1604	Multiple trees show evidence of contacting the primary conductor.
370.	11528 SE Tyler Road, Happy Valley (45.4504, -122.5438)	D1227D 4340	Multiple trees show evidence of contacting the primary conductor.
371.	9615 SE Eastview Drive, Happy Valley (45.4536, -122.5482)	D1227C 3489	Two trees show evidence of contacting the primary conductor.
372.	On SE Ridgeway Drive, Happy Valley (45.4539, -122.5505)	D1227B 5034 to D1227B 5241	Multiple trees show evidence of contacting the primary conductor.

373.	On SE 129TH Avenue, Happy Valley (45.4380, -122.5358)	D1235C 1556 to D1235C 1555	Multiple trees show evidence of contacting the primary conductor.
374.	On SE King Road, Happy Valley (45.4470, -122.5247)	D1226D 3466 to D1226D 9302	Multiple trees show evidence of contacting the primary conductor.
375.	On SE Richey Road, Gresham (45.4654, -122.4812)	D1319D 3270	Tree shows evidence of contacting the primary conductor.
376.	17745 SE Richey Road, Gresham (45.4656, -122.4793)	D1319D 4727	Two trees show evidence of contacting the primary conductor.
377.	On SE Regner Road, Gresham (45.4782, -122.4292)	D1315C 737	Tree shows evidence of contacting the primary conductor. Tree wire.
378.	On SE Clatsop Street, Happy Valley (45.4614, -122.5195)	D1223D 6045	Multiple trees show evidence of contacting the primary conductor.
379.	8690 SE 140TH Place, Happy Valley (45.4600, -122.5197)	D1226A 6821	Tree shows evidence of contacting the primary conductor.
380.	13463 SE Kanne Road, Happy Valley (45.4573, -122.5246)	D1226A 6618	Tree shows evidence of contacting the primary conductor.

Citation C:	**Obstructions on pole such as vines, nails, tacks and through bolts not properly trimmed create a climbing hazard.**
Reference:	**NESC Rule Number:** 217A4

	Locations	*Pole Numbers*	*Comments*
1.	1537 South Dogwood Street, Cornelius (45.5166, -123.0526)	C1303B 714	Vines engulfing pole are creating a **climbing hazard**.
2.	12473 Ferry Road NE, Aurora (45.2132, -122.8056)	C4121A 3718	Vines engulfing pole and approaching primary conductor are **creating a hazard**.
3.	2796 Glen Haven Road, Lake Oswego (45.4031, -122.7064)	D2117A 5042	Vines engulfing pole and approaching primary conductor are **creating a hazard**.
4.	17731 SE River Road, Portland (45.3945, -122.6236)	D21130D 1570	Vines engulfing pole and approaching primary conductor are **creating a hazard**.
5.	Intersection of SE Aldercrest Court and SE Thiessen Road, Portland (45.4162, -122.5992)	D2208B 2858	Vines engulfing pole and approaching primary conductor are **creating a hazard**.
6.	1740 Baker Street NE, Salem (44.9529, -123.0174)	C73-23A 3268	Vines engulfing pole are creating a **climbing hazard**.
7.	On Lockhaven Drive North, Keizer (45.0044, -123.0278)	C63-35C 3104	Vines engulfing pole are creating a **climbing hazard**.
8.	1356 Meadowlark Drive, Keizer (45.0122, -123.0149)	C63-35A 2356	Vines engulfing pole and approaching primary conductor are **creating a hazard**.
9.	2710 SE Rutland Terrace, Portland (45.5209, -122.7082)	A1132D 61	Vines engulfing pole and approaching primary conductor are **creating a hazard**.

10.	Across from 114 SW Kingston Avenue, Portland (45.5237, -122.7063)	A1132D 546	Vines engulfing pole and approaching primary conductor are **creating a hazard**.
11.	On SW Prosperity Park Road, Tualatin (45.3712, -122.7300)	D21-30A 4634	Vines engulfing pole and approaching primary conductor are **creating a hazard**.
12.	On SW Mountain Road, West Linn (45.3536, -122.7098)	D21-32A 3233	Vines engulfing pole are creating a **climbing hazard**.
13.	On SW Schaeffer Road, West Linn (45.3527, -122.7088)	D21-32D 3231	Vines engulfing pole are creating a **climbing hazard**.
14.	On SW Gopher Valley Road, Sheridan (45.1694, -123.3783)	C56-01B 255	Vines engulfing pole are creating a **climbing hazard**.
15.	311 Ganong Street, Oregon City (45.3462, -122.6194)	D3206B 1752	Vines engulfing pole are creating a **climbing hazard**.
16.	14831 South Maplelane Road, Oregon City (45.3371, -122.5614)	D3204D 165	Vines engulfing pole are creating a **climbing hazard**.
17.	247 SE 4th Street, Troutdale (45.5387, -122.3864)	A1325C 7000	Vines engulfing pole and approaching primary conductor are **creating a hazard**.
18.	921 SW Davenport Street, Portland (45.5054, -122.6879)	D11-04D 322	Vines engulfing pole are creating a **climbing hazard**.
19.	840 SW Canning Street, Portland (45.5046, -122.6879)	D11-09A 155	Vines engulfing pole are creating a **climbing hazard**.
20.	5166 SW 26th Drive, Portland (45.4854, -122.7066)	D11-17A 4630	Vines engulfing pole are creating a **climbing hazard**.
21.	6510 SW 32nd Avenue, Portland (45.4775, -122.7095)	D11-17D 2663	Vines engulfing pole are creating a **climbing hazard**.
22.	3539 SW Nevada Court, Portland (45.4726, -122.7134)	D11-20B 3	Vines engulfing pole and approaching primary conductor are **creating a hazard**.
23.	Intersection Of South Blount Road and South Bremer Road, Canby (45.2711, -122.6557)	D3135B 521	Vines engulfing pole are creating a **climbing hazard**.

Citation D:	**For conductors energized below 600 volts, an operator of electric supply facilities must trim vegetation to prevent it from causing strain or abrasion on electric conductors. Where trimming or removal of vegetation is not practical, the operator of electric supply facilities must install suitable material or devices to avoid insulation damage by abrasion.**
Reference:	**NESC Rules Number:** 012C, 218 and OAR 860-024-0016 (6)

	Locations	*Pole Numbers*	*Comments*
1.	On NW Davidson Road, Banks (45.6326, -123.0755)	B2329A 1152	Dead limb leaning on neutral conductor and straining.
2.	Across from 16389 South Hagen Road, Happy Valley (45.4394, -122.4951)	D1331B 3908	Limb is leaning on neutral conductor and straining.

REMARKS

The programs reviewed during this inspection relate to NESC requirements for the construction, inspection, testing, repair, and quality control of line facilities to assure ongoing safety compliance. For general maintenance requirements refer to NESC Rules 121, 214, and 313. Also, see OAR 860-024-0016 outlined below, for Minimum Vegetation Clearance Requirements of utility facilities. Those items noted below with a **"CAUTION"** indicate NESC program areas that need improvement to ensure safety compliance.
A **"WARNING"** is indicative of program deficiencies of a more serious, potentially system wide, nature.

OAR 860-024-0016
Under reasonably anticipated operational conditions, an operator of electric supply facilities must maintain the following minimum clearances from conductors:
(a) Ten feet for conductors above 200,000 volts.
(b) Seven and one-half feet for conductors energized at 50,001 through 200,000 volts.
(c) Five feet for conductors energized at 600 through 50,000 volts.
(A) Clearances may be reduced to three feet if the vegetation is not readily climbable.
(B) Intrusion of limited small branches and new tree growth into this minimum clearance area is acceptable provided the vegetation does not come closer than six inches to the conductor.

OPUC Safety Staff recently performed the annual review of the PGE vegetation management program. This occurred primarily from July 26 to August 22, 2022, in the communities and rural areas listed within the body of the report.

Staff's report identifies locations where contact between vegetation and energized high voltage conductors have been identified. Many trees, although not actively in contact with a conductor, had less than the minimum clearances prescribed by the Administrative Rule. Staff notes these as observations because direct measurement is not possible or feasible during the review.

Staff is optimistic regarding the trim cycle modifications PGE has proposed and adopted which should continue to improve the vegetation management program. The short-term data from Safety Staff audits starting in 2020 indicates the number of tree and energized primary conductor contacts continues to decrease. The instances of "cycle buster" and end of cycle energized conductor tree contacts remains to be a high percentages of tree contacts recorded by Staff. Maintenance of tree-to-conductor clearances, in general, specifically those in High Fire Risk Zones (HFRZ) are not adequate to meet the Oregon Administrative Rule throughout the duration of the trim cycle and should be addressed. A historical graph of readily climbable trees and primary conductor vegetation contacts, including contacts in High Fire Risk Zones (HFRZ) is attached for your reference.

Safety staff noted that tree crew numbers in the field do not seem to reflect the crew numbers quoted during PGE's first quarter meeting of this year and show a decline from the number of crews observed in previous years.

Staff observed **407** locations where evidence existed of contact between vegetation and primary electrical conductors. The identified locations resulted in conservatively over **609** primary conductor vegetation contacts.

A breakdown of the locations follows:

- Nineteen locations are readily climbable trees noted as **hazardous conditions** in Citation: A.

- Five of the nineteen readily climbable tree locations noted above, involve two or more trees contacting primary conductors.

- Of the three hundred and eighty locations identified in Citation: B, one hundred and eleven locations involve two or more trees contacting primary conductors.

- Sixteen locations within Citations A and B, were located within a PGE's High Fire Risk Zones (HFRZ). The number of violations identified indicates the company's vegetation management program is not adequately addressing the vegetation energized conductor contacts in the elevated risk High Fire Risk Zones (HFRZ).

- One location: Citation B. 290, a **hazard**, in an orchard with agriculture workers working around harvestable trees contacting energized conductors. This issue has been previously identified in Staff reports E04-61, E07-29, E18-34, E20-49, and E21-53.

- Eight locations in Citation: C, involve vines that have grown up poles and guy wires, touching or about to touch, energized primary conductors. These violations are considered to be **hazardous conditions**.

- Fifteen locations in Citation: C, involve vines that have grown on poles creating **climbing hazards**.

- Two locations were observed and noted where limbs were leaning on a primary neutral creating strain on the conductor.

RECOMMENDATIONS: The OPUC Staff recommends Portland General Electric perform the following actions:

1. On or before September 30, 2022, submit documentation confirming correction of the probable violations related to **readily climbable trees**, as well as those listed specifically as **hazardous conditions**.

2. On or before February 27, 2023, submit documentation confirming correction of the remaining probable violations cited in this report.

If a time extension is needed, submit a written request stating the reason(s) for the delay and the proposed schedule to complete the work. If government permits are causing a delay, include the date the permits were applied for, and a permitting agency contact person and telephone number. If you disagree with any cited probable violation, please furnish Staff a letter within 30 days requesting an informal conference.

Each electric supply and telecommunication operator in Oregon, (defined in OAR 860-024-0001(5)), is responsible to construct, operate, and maintain its line facilities in compliance with the NESC. Refer to ORS 757.035 and OARs 860-024-0010 and 860-023-0005 for Oregon laws and rules regarding minimum OPUC safety standards. Particular focus should be given to NESC Rules 090,110 121, 214, 313, and OAR 860-024-0011, which address ongoing inspection and maintenance responsibilities.

Failure to comply with the OPUC safety regulations or NESC rules can result in Commission orders and/or civil penalties. Refer to ORS 757.990(1) for penalty amounts.

If you have any questions regarding this report, please contact, Leon Grumbo at (503) 881-7707 or Steve Sims at (503) 339-6749 or Alex Chaney at (503) 559-4011. Please reply to OPUC.NESCSafety@state.or.us for report updates, time extensions, or to close the report in the OPUC enforcement log.

Prepared by:

Attachments: Photographs
Historical Vegetation Graph

Attachment A
OPUC Safety Report
E22-62R 1

Probable violation A.1:
Hazard: Multiple readily climbable trees show evidence of contacting the primary conductor on Sunnyview Road NE, Salem.
(44.9561, -123.0100)

Probable violation A.2:
Hazard: Readily climbable tree shows evidence of contacting the primary conductor in the alley behind 1450 Jefferson Street NE, Salem.
(44.9520, -123.0164)

Probable violation A.3:
Hazard: Readily climbable tree shows evidence of contacting the primary conductor at 540 SW Dennis Avenue, Hillsboro. (45.5167, -122.9958)

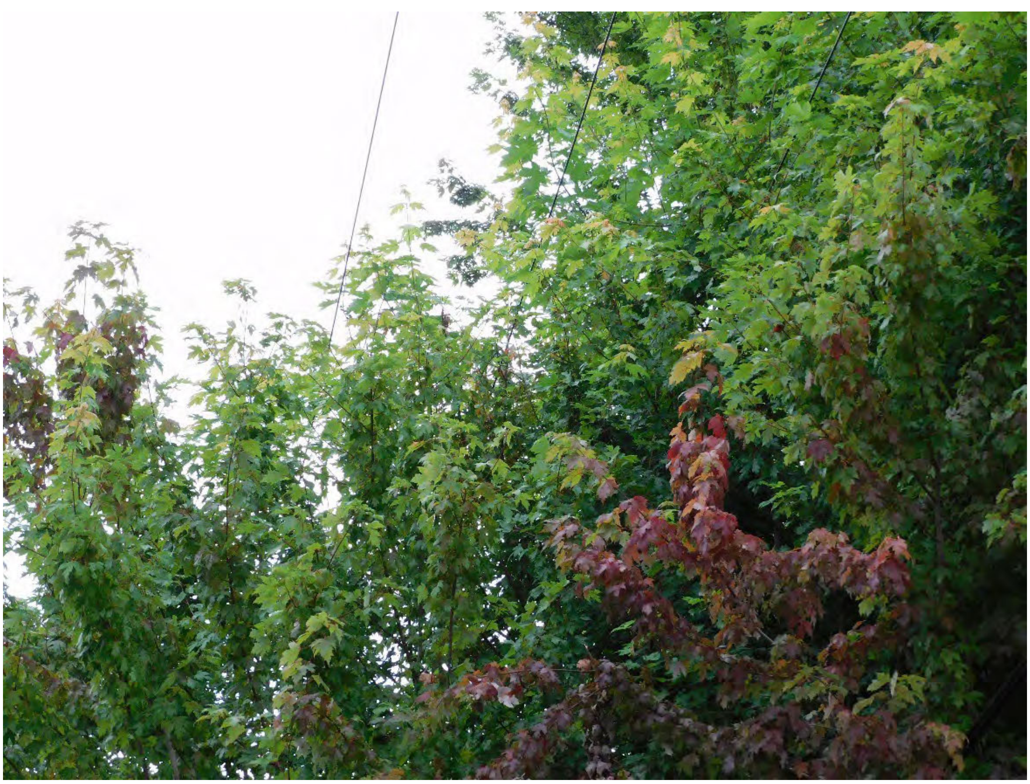
Probable violation A.4:
Hazard: Readily climbable tree shows evidence of contacting the primary conductor at 5870 SW Delker Road, Tualatin. (45.3609, -122.7373)

Attachment A
OPUC Safety Report
E22-62R 1

Probable violation A.5:
Hazard: Two readily climbable trees show evidence of contacting the primary conductor at 22281 SW 55th Avenue, Tualatin. (45.3588, -122.7330)

Probable violation A.6:
Hazard: Multiple readily climbable trees show evidence of contacting the primary conductor on SW Schatz Road, Tualatin. (45.3574, -122.7312)

Probable violation A.7: **Hazard: Readily climbable tree shows evidence of contacting the primary conductor** across from 7142 SE 302nd Avenue, Gresham. (45.4712, -122.3525)



Probable violation A.8: **Hazard: Readily climbable tree shows evidence of contacting the primary conductor** at 2879 SE 16th Street, Gresham. (45.4855, -122.4037)

Probable violation A.9:
Hazard: Readily climbable tree shows evidence of contacting the primary conductor at 5017 SE Tolman Street, Portland.
(45.4771, -122.6109)

Probable violation A.10:
Hazard: Multiple readily climbable trees show evidence of contacting the primary conductor at 1555 SW Borland Road, West Linn.
(45.3654, -122.6925)

Probable violation A.11: **Hazard: Readily climbable tree shows evidence of contacting the primary conductor** at 681 SW Borland Road, West Linn. (45.3550, -122.6829)

Probable violation A.12: **Hazard: Readily climbable tree shows evidence of contacting the primary conductor** at 1293 14th Street, West Linn. (45.3413, -122.6553)

Probable violation A.13:
Hazard: Readily climbable tree shows evidence of contacting the primary conductor at 7708 Sunnybrook Lane SE, Salem.
(44.8437, -122.9042)

Probable violation A.14:
Hazard: Multiple spans of readily climbable trees show evidence of contacting the primary conductor at 3790 Fisher Road NE, Salem.
(44.9739, -122.9884)

Probable violation A.15: **Hazard: Readily climbable tree shows evidence of contacting the primary conductor** at 4290 45th Ave NE, Salem.
(44.9813, -122.9730

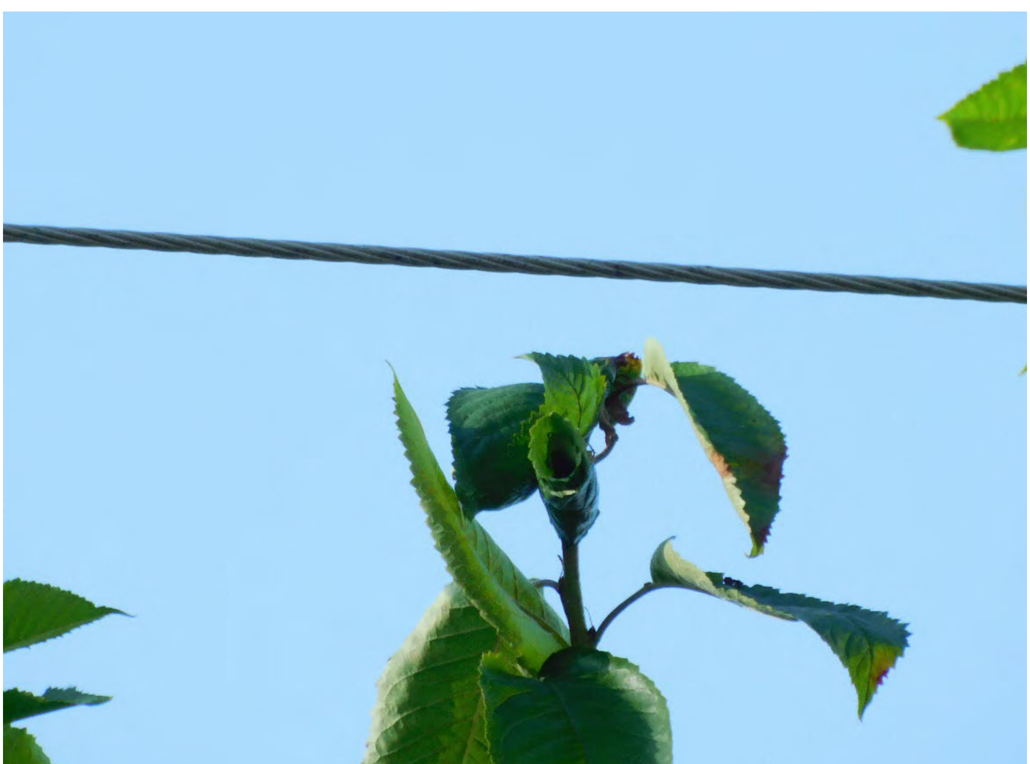
Probable violation A.16: **Hazard: Readily climbable tree shows evidence of contacting the primary conductor** at 23215 SW Newland Road, Wilsonville.
(45.3520, -122.7228)

Probable violation A.17: **Hazard: Readily climbable tree shows evidence of contacting the primary conductor** on South Haines Road, Canby. (45.2723, -122.6610)

Probable violation A.18: **Hazard: Readily climbable tree shows evidence of contacting the primary conductor** across from 7142 SE 302nd Avenue, Gresham. (45.4712, -122.3525)

Probable violation A.19: **Hazard: Readily climbable tree shows evidence of contacting the primary conductor** at 2879 SE 16th Street, Gresham.
(45.4855, -122.4037)

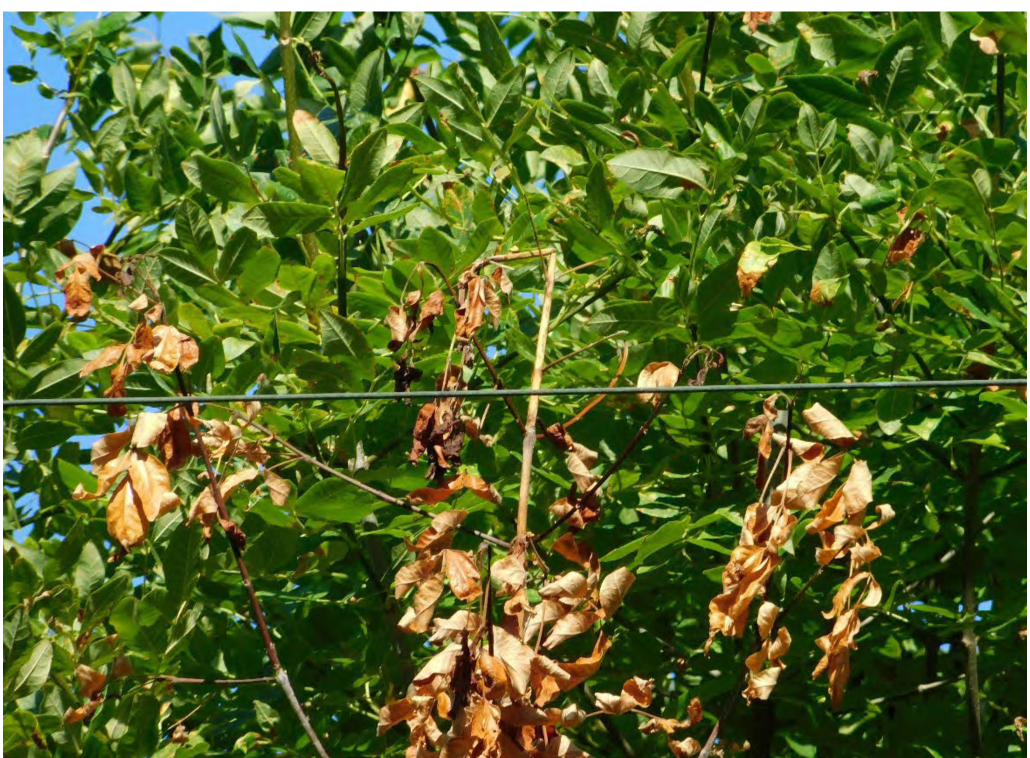
Probable violation B.1:
Tree shows evidence of contacting primary conductors on Kuebler Blvd., South, Salem.
(44.8832, -123.0847)



Probable violation B.2:
Tree shows evidence of contacting primary conductors on Kuebler Blvd. South, Salem.
(44.8832, -123.0803)

Attachment A
OPUC Safety Report
E22-62R 2

Probable violation B.3:
Tree shows evidence
of contacting primary
conductors at
5045 River Road South,
Salem.
(44.8824, -123.1369)



Probable violation B.4:
Tree shows evidence
of contacting primary
conductors on
River Road South, Salem.
(44.8799, -123.1387)

Probable violation B.5:
Two trees show evidence of contacting the primary conductor on River Road South, Salem.
(44.8878, -123.1334)

Probable violation B.6:
Two trees show evidence of contacting the primary conductor at 4335 River Road South, Salem.
(44.8931, -123.1304)

Probable violation B.7:
Tree shows evidence
of contacting primary
conductors at
5089 Riverdale Road
South, Salem.
(44.8824, -123.1270)

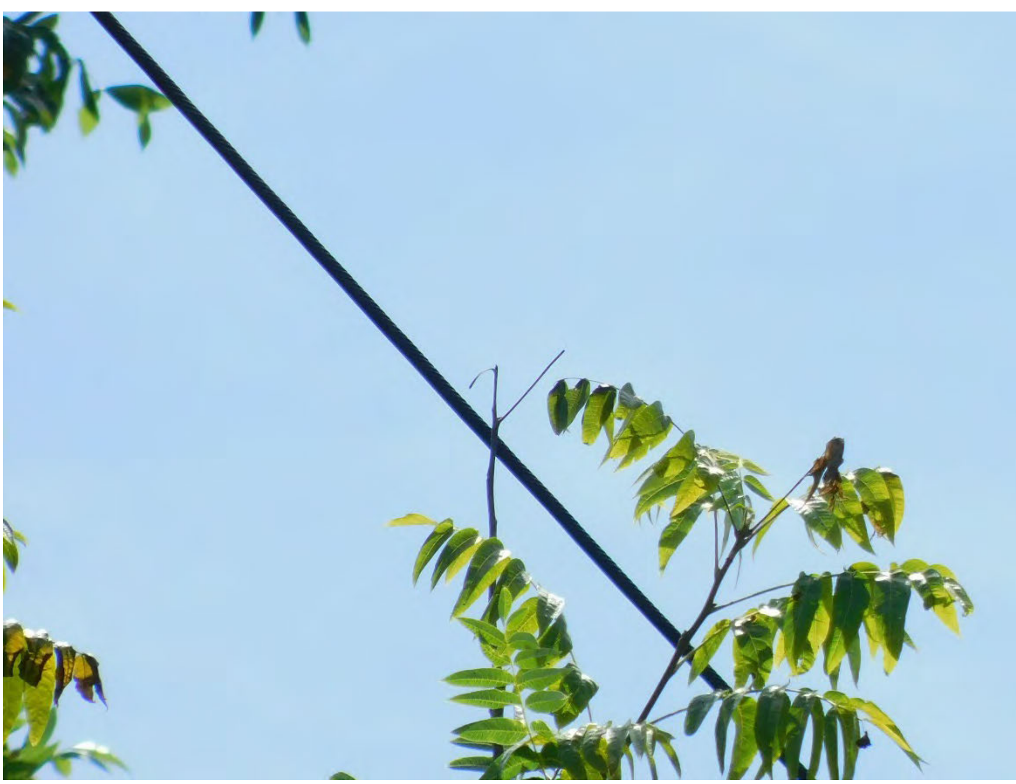
Probable violation B.8:
Tree shows evidence
of contacting primary
conductors on
River Road South, Salem.
(44.9021, -123.1019)

Probable violation B.9: Multiple trees show evidence of contacting the primary conductor on Jackson Hill Road SE, Salem.
(44.8322, -123.0301)

Probable violation B.10: Tree shows evidence of contacting primary conductors on Boone Road SE, Salem.
(44.8823, -123.0458)

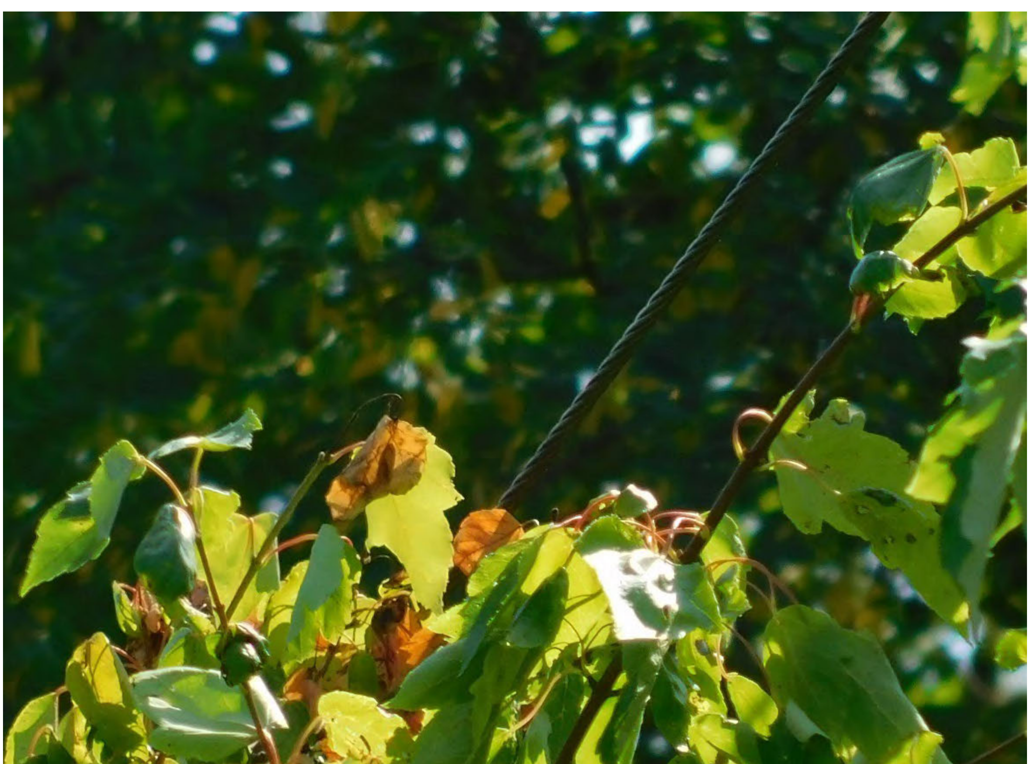
Attachment A
OPUC Safety Report
E22-62R 2

Probable violation B.11:
Tree shows evidence of contacting primary conductors at 695 15th Street NE, Salem.
(44.9426, -123.0196)



Probable violation B.12:
Tree shows evidence of contacting primary conductors at 590 14th Street NE, Salem.
(44.9415, -123.0217)

Probable violation B.13:
Tree shows evidence of contacting primary conductors at 631 Winter Street NE, Salem.
(44.9446, -123.0294)



Probable violation B.14:
Tree shows evidence of contacting primary conductors at 1340 Nebraska Avenue NE, Salem.
(44.9472, -123.0193)

Attachment A
OPUC Safety Report
E22-62R 2

Probable violation B.15:
Multiple trees show evidence of contacting the primary conductor on Gibson Road NW, Salem.
(44.9813, -123.1039)

Probable violation B.16:
Tree shows evidence of contacting primary conductors on
Bruch College Road NW, Salem.
(45.0125, -123.1292)

Probable violation B.17: Multiple trees show evidence of contacting the primary conductor on Spring Valley Road NW, Salem.
(45.0354, -123.1182)

Probable violation B.18: Tree shows evidence of contacting primary conductors on Maples Street North, Keizer.
(45.0137, -123.0621)

Attachment A
OPUC Safety Report
E22-62R 2

Probable violation B.19:
Tree shows evidence of contacting primary conductors at 8275 Wheatland Road North, Keizer.
(45.0389, -123.0177)

Probable violation B.20:
Tree shows evidence of contacting primary conductors on Donald Road NE, Donald.
(45.2207, -122.8311)

Probable violation B.21:
Tree shows evidence of contacting primary conductors on NE Butteville Road, Aurora.
(45.2890, -122.7934)

Probable violation B.22:
Multiple trees show evidence of contacting the primary conductor at 26350 NE Butteville Road, Aurora.
(45.2859, -122.7729)

Probable violation B.23:
Tree shows evidence
of contacting primary
conductors on
NE Boones Ferry Road,
Aurora.
(45.2868, -122.7751)

Probable violation B.24:
Tree shows evidence
of contacting primary
conductors at
29560 NW Olson Road,
Gaston.
(45.4301, -123.1529)

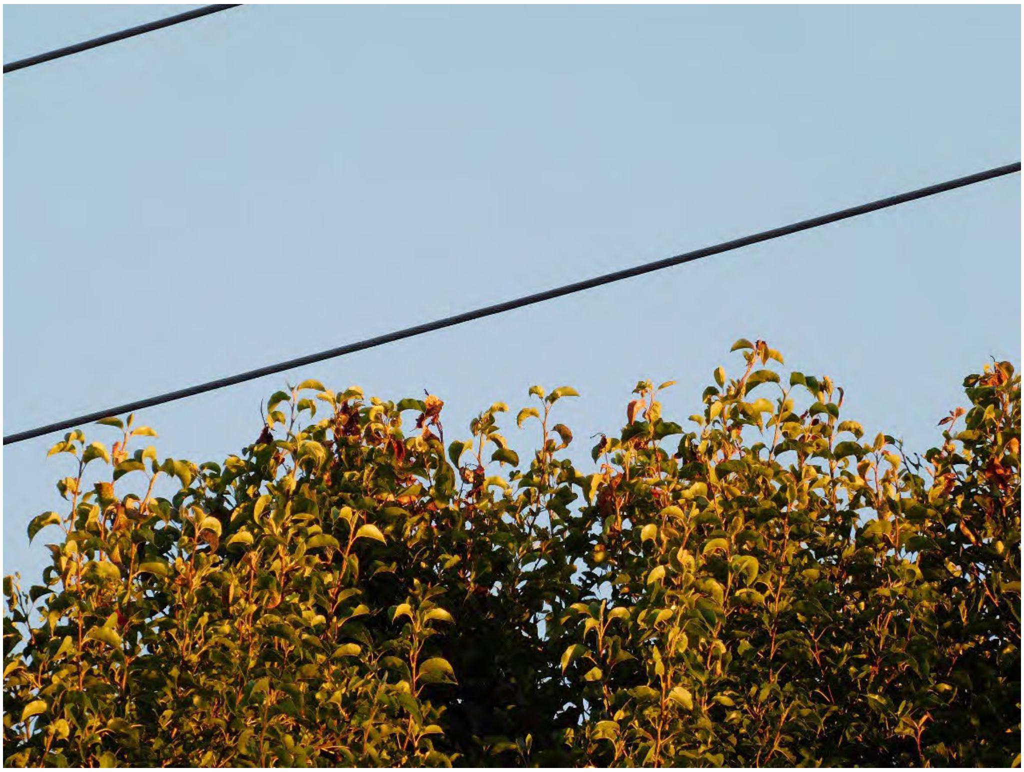
Probable violation B.25:
Tree shows evidence
of contacting primary
conductors on
NW Goodin Creek Road,
Gaston.
(45.4108, -123.1452)
HFRZ

Probable violation B.26:
Tree shows evidence
of contacting primary
conductors at
1038 Hwy 47, Carlton.
(45.2872, -123.1748)

Attachment A
OPUC Safety Report
E22-62R 2

Probable violation B.27: Tree shows evidence of contacting primary conductors on Willamina Creek Road, Willamina.
(45.1068, -123.4968)

Attachment A
OPUC Safety Report
E22-62R 3



Probable violation B.28: Multiple trees show evidence of contacting the primary conductor on SW Sunset Blvd, Sherwood.
(45.3499, -122.8314)

Probable violation B.29: Tree shows evidence of contacting primary conductors on SW Beef Bend Road, Portland.
(45.4018, -122.8299)

Probable violation B.30:
Tree shows evidence
of contacting primary
conductors at
630 SW Dennis Avenue,
Hillsboro.
(45.5157, -122.9958)

Probable violation B.31:
Multiple trees show
evidence of contacting
the primary conductor
on SW Tongue Lane,
Cornelius.
(45.4838, -123.0480)

Probable violation B.32:
Tree shows evidence of contacting primary conductors at 36260 SW Tongue Lane, Cornelius.
(45.4838, -123.0498)

Probable violation B.33:
Multiple trees show evidence of contacting the primary conductor at 32710 SW Tongue Lane, Cornelius.
(45.4849, -123.0141)

Attachment A
OPUC Safety Report
E22-62R 3

Probable violation B.34:
Tree shows evidence
of contacting primary
conductors on
SW Laurelwood Road,
Gaston.
(45.4248, -123.0896)

Probable violation B.35:
Tree shows evidence
of contacting primary
conductors at
46633 NW Sell Road,
Banks.
(45.4849, -123.0141)

Attachment A
OPUC Safety Report
E22-62R 3

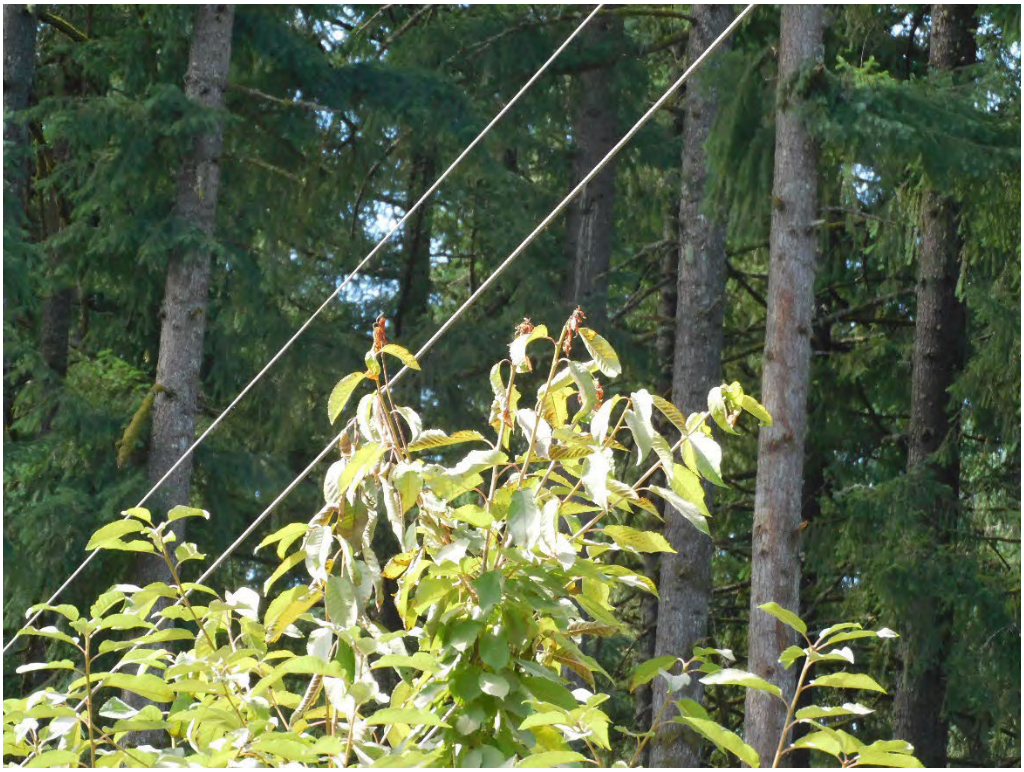
Probable violation B.36:
Tree shows evidence
of contacting primary
conductors at
38760 NW Harrison Road,
Banks.
(45.6216, -123.0760)

Probable violation B.37:
Tree shows evidence
of contacting primary
conductors on
NW Hahn Road, Banks.
(45.6282, -123.0729)

Probable violation B.38:
Tree shows evidence
of contacting primary
conductors on
NW Davidson Road,
Banks.
(45.6425, -123.0825)
HFRZ

Probable violation B.39:
Tree shows evidence
of contacting primary
conductors on
NW Davidson Road,
Banks.
(45.6463, -123.0835)
HFRZ

Attachment A
OPUC Safety Report
E22-62R 3



Probable violation B.40:
Tree shows evidence
of contacting primary
conductors at
15327 NW Old Pumpkin
Ridge Road, North Plains.
(45.6314, -123.0113)
HFRZ

Probable violation B.41:
Tree shows evidence
of contacting primary
conductors at
2200 NW Susbauer Road,
Cornelius.
(45.5360, -123.0432)

Attachment A
OPUC Safety Report
E22-62R 3

Probable violation B.42: Multiple trees show evidence of contacting the primary conductor at 3865 Baseline Street, Hillsboro.
(45.5199, -123.0238)

Probable violation B.43: Tree shows evidence of contacting primary conductors on SW Tualatin Valley Highway, Hillsboro.
(45.5199, -123.0166)

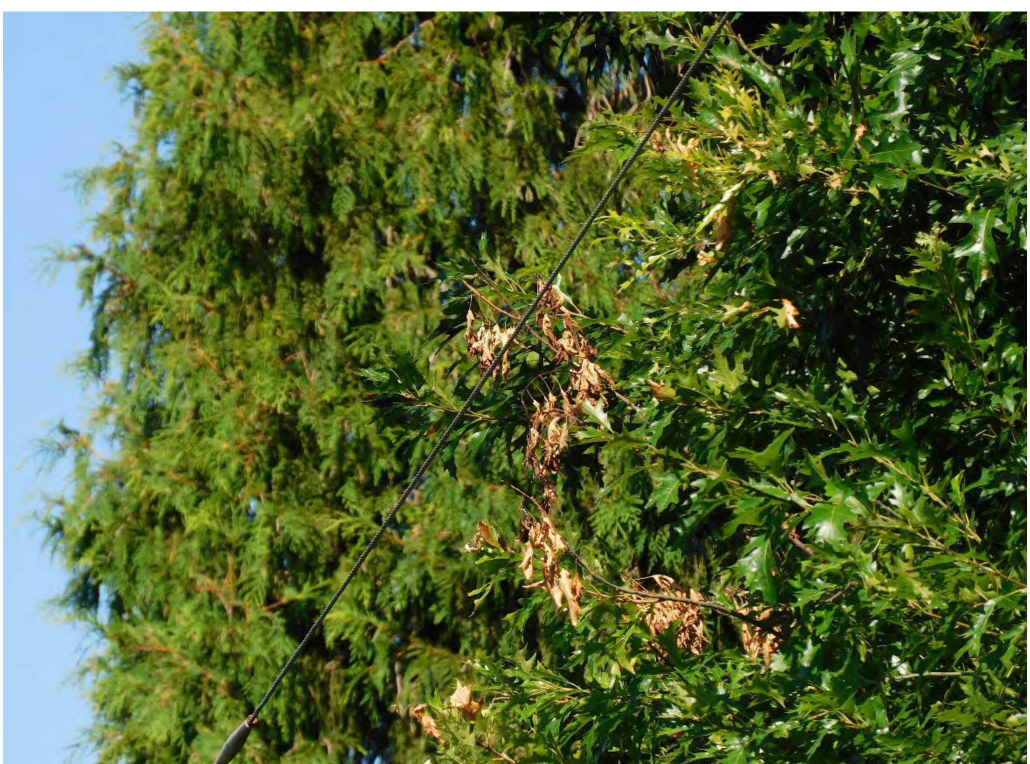
Probable violation B.44: Two trees show evidence of contacting the primary conductor at 1050 SW Baseline Street, Hillsboro.
(45.5191, -123.0017)

Probable violation B.45: Multiple trees show evidence of contacting the primary conductor on NE 25th Avenue, Hillsboro.
(45.5438, -122.9575)

Probable violation B.46: Multiple trees show evidence of contacting the primary conductor on NE 15th Avenue, Hillsboro.
(45.5402, -122.9663)

Probable violation B.47: Two trees show evidence of contacting the primary conductor at 1485 NE Sunrise Lane, Hillsboro.
(45.5367, -122.9665)

Probable violation B.48:
Tree shows evidence
of contacting primary
conductors at
1299 NE 17th Avenue,
Hillsboro.
(45.5345, -122.9646)



Probable violation B.49:
Tree shows evidence
of contacting primary
conductors at
1549 NE Jackson School
Road, Hillsboro.
(45.5361, -122.9801)

Probable violation B.50:
Tree shows evidence
of contacting primary
conductors at
895 NE Melinda Court,
Hillsboro.
(45.5389, -122.9755)

Probable violation B.51:
Tree shows evidence
of contacting primary
conductors at
14510 NW Pioneer Road,
Beaverton.
(45.5214, -122.8262)

Probable violation B.52:
Tree shows evidence
of contacting primary
conductors at
211 NW Gina Way,
Beaverton.
(45.5216, -122.8878)

Probable violation B.53:
Tree shows evidence
of contacting primary
conductors at
1276 NW Perl Way,
Beaverton.
(45.5288, -122.8891)

Probable violation B.54:
Tree shows evidence of contacting primary conductors at
4065 SE Bentley Street, Hillsboro.
(45.5123, -122.9410)

Probable violation B.55:
Tree shows evidence of contacting primary conductors at
3149 SE Fairview Blvd., Portland.
(45.5194, -122.7146)

Probable violation B.56:
Multiple trees show evidence of contacting the primary conductor at 337 SE Kingston Avenue, Portland.
(45.5208, -122.7069)

Probable violation B.57:
Tree shows evidence of contacting primary conductors at 127 SE Kingston Avenue, Portland.
(45.5231, -122.7069)

Probable violation B.58: Multiple trees show evidence of contacting the primary conductor behind 1264 NW Summit Avenue, Portland. (45.5323, -122.7083)

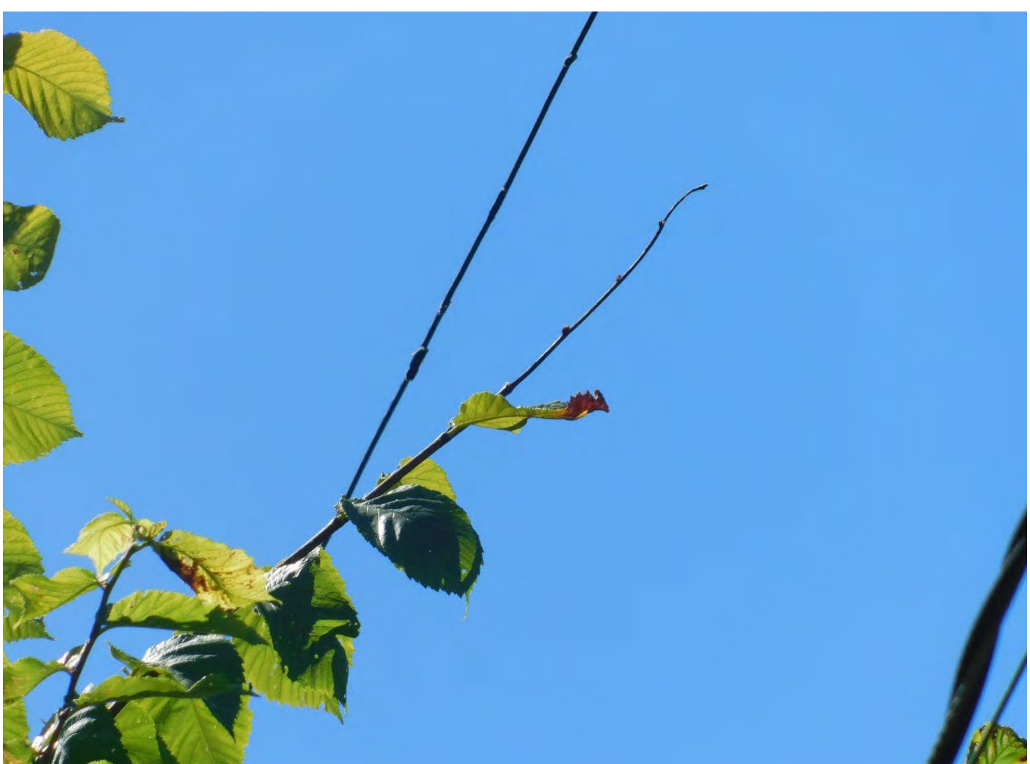
Probable violation B.59: Multiple trees show evidence of contacting the primary conductor at 2682 NW Cornell Road, Portland. (45.5313, -122.7068)

Probable violation B.60:
Tree shows evidence
of contacting primary
conductors at
2610 NW Cornell Road,
Portland.
(45.5298, -122.7048)

Probable violation B.61:
Tree shows evidence
of contacting primary
conductors at
824 NE 18th Avenue,
Portland.
(45.5292, -122.6894)

Attachment A
OPUC Safety Report
E22-62R 3

Probable violation B.62:
Multiple trees show evidence of contacting the primary conductor at 2250 NW Kearny Street, Portland.
(45.5290, -122.6976)



Probable violation B.63:
Tree shows evidence of contacting primary conductors at
2486 NW Kearny Street, Portland.
(45.5290, -122.7025)

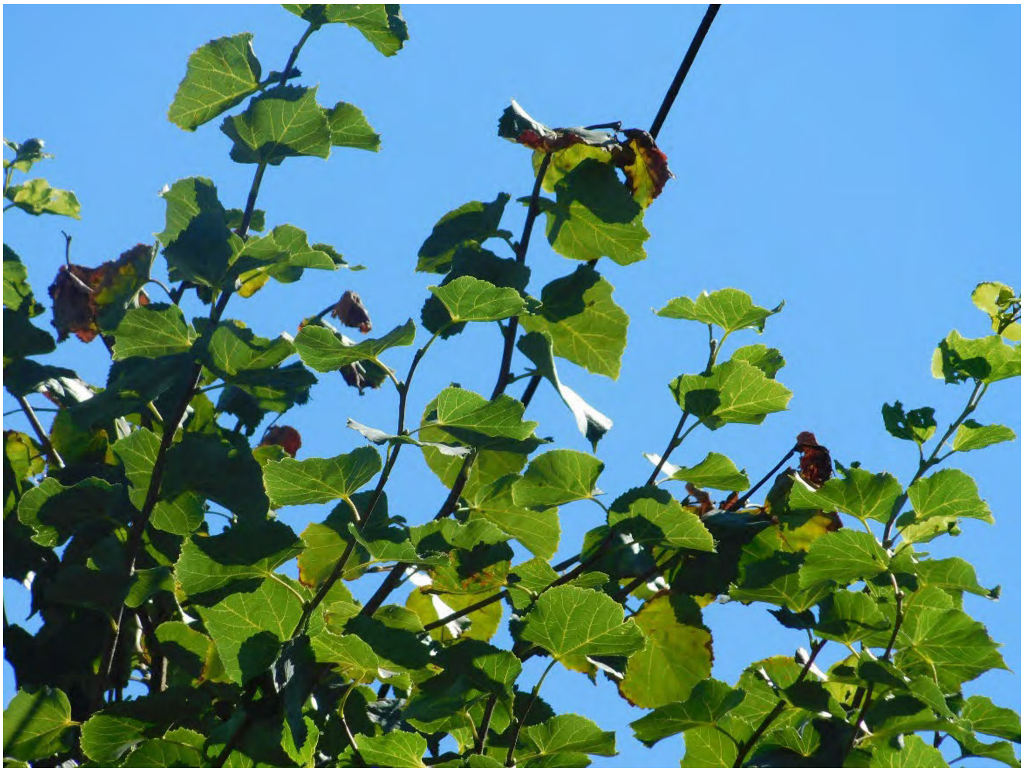
Probable violation B.64:
Tree shows evidence
of contacting primary
conductors at
2182 NW Hoyt Street,
Portland.
(45.5269, -122.6964)

Probable violation B.65:
Tree shows evidence
of contacting primary
conductors at
1931 NW Flanders Street,
Portland.
(45.5263, -122.6913)

Probable violation B.66:
Tree shows evidence
of contacting primary
conductors at
2230 NW Glisan Street,
Portland.
(45.5262, -122.6973)

Probable violation B.67:
Tree shows evidence
of contacting primary
conductors at
1137 NW 23rd Avenue,
Portland.
(45.5312, -122.6988)

Attachment A
OPUC Safety Report
E22-62R 3



Probable violation B.68:
Tree shows evidence
of contacting primary
conductors at
2046 NW Overton Street,
Portland.
(45.5319, -122.6936)

Probable violation B.69:
Tree shows evidence
of contacting primary
conductors at
2376 NW Overton Street,
Portland.
(45.5318, -122.7002)

Probable violation B.70: Multiple trees show evidence of contacting the primary conductor at 2066 NW Pettygrove Street, Portland. (45.5327, -122.6942)

Probable violation B.71: Multiple trees show evidence of contacting the primary conductor at 2844 NW Raleigh Street, Portland. (45.5338, -122.7097)

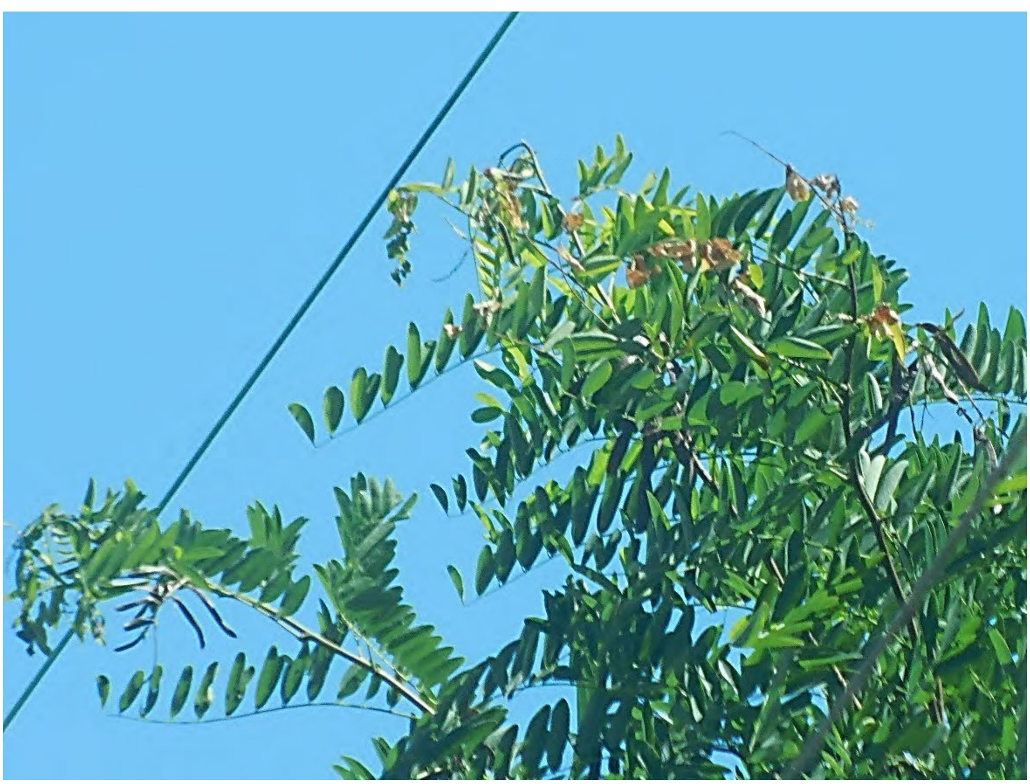
Probable violation B.72:
Tree shows evidence
of contacting primary
conductors at
2926 NW Raleigh Street,
Portland.
(45.5338, -122.7115)

Probable violation B.73:
Tree shows evidence
of contacting primary
conductors at
2644 NW Thurman Street,
Portland.
(45.5353, -122.7058)

Probable violation B.74:
Tree shows evidence
of contacting primary
conductors at
3139 NW Vaughn Street,
Portland.
(45.5367, -122.7147)

Probable violation B.75:
Tree shows evidence
of contacting primary
conductors at
3275 NW 29th Avenue,
Portland.
(45.5464, -122.7111)

Probable violation B.76: Tree shows evidence of contacting primary conductors at 4465 NW Yeon Avenue, Portland. (45.5545, -122.7329)

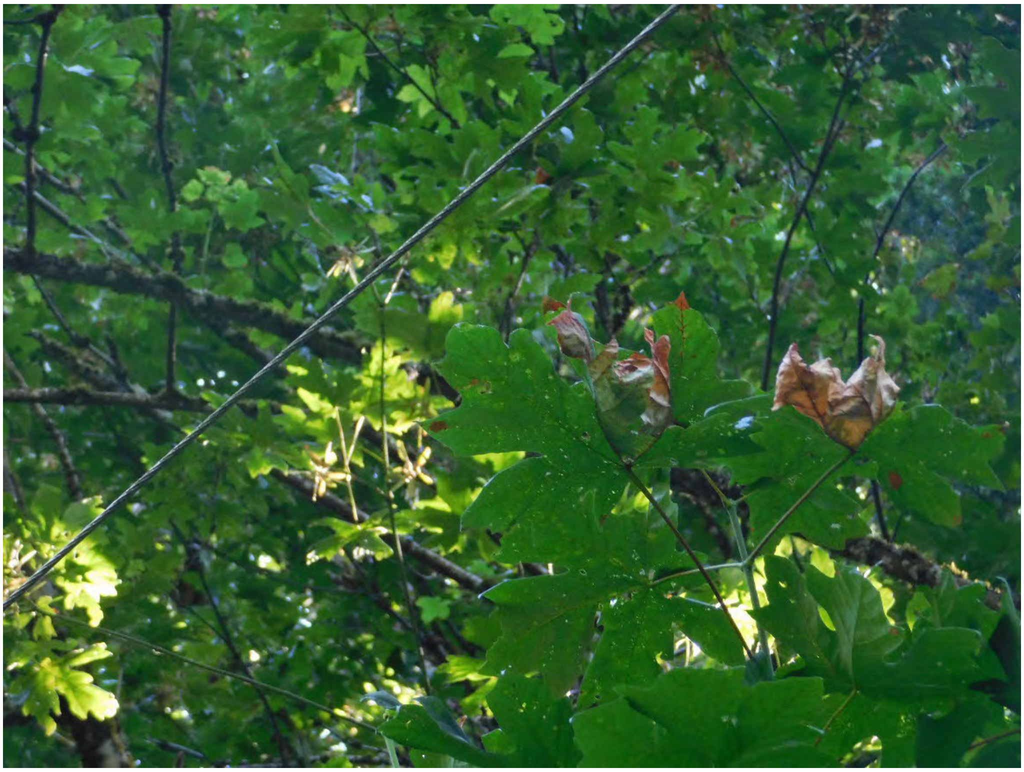


Probable violation B.77: Tree shows evidence of contacting primary conductors at 3344 NW Industrial Avenue, Portland. (45.5412, -122.7166)

Probable violation B.78:
Tree shows evidence
of contacting primary
conductors at
6516 SW Barnes Road,
Portland.
(45.5157, -122.7437)

Probable violation B.79:
Tree shows evidence
of contacting primary
conductors at the
intersection of SW
Arboretum Circle and
West Burnside Road,
Portland.
(45.5191, -122.7227)
HFRZ

Attachment A
OPUC Safety Report
E22-62R 3



Probable violation B.80:
Tree shows evidence of contacting primary conductors at 2981 NW 53rd Drive, Portland.
(45.5440, -122.7485)
HFRZ

Probable violation B.81:
Two trees show evidence of contacting the primary conductor at 8221 NW Cresap Lane, Portland.
(45.5450, -122.7612)
HFRZ

Probable violation B.82: Tree shows evidence of contacting primary conductors across from 3744 NW Devoto Lane, Portland. (45.5503, -122.7708)

Probable violation B.83: Multiple trees show evidence of contacting the primary conductor behind 3756 NW Devoto Lane, Portland. (45.5512, -122.7714)

Probable violation B.84:
Tree shows evidence of contacting primary conductors at the intersection of NW Wind Ridge Drive and NW Skyline Blvd., Portland.
(45.5570, -122.7796)

Probable violation B.85:
Tree shows evidence of contacting primary conductors at 13941 Northwest Glendoveer Drive, Portland.
(45.5960, -122.8217)
HFRZ

Attachment A
OPUC Safety Report
E22-62R 3

Probable violation B.86:
Tree shows evidence
of contacting primary
conductors at
11724 Northwest
McNamee Road, Portland.
(45.6075, -122.8352)
HFRZ

Probable violation B.87:
Tree shows evidence
of contacting primary
conductors across from
12615 NW Skyline Blvd.,
Portland.
(45.6145, -122.8667)
HFRZ

Probable violation B.88:
Tree shows evidence
of contacting primary
conductors on
NW Skyline Blvd.,
Portland.
(45.6689, -122.9109)
HFRZ

Probable violation B.89:
Tree shows evidence
of contacting primary
conductors on SW Pfaffle
Street, Portland.
(45.4380, -122.7580)

Probable violation B.90:
Tree shows evidence
of contacting primary
conductors across from
7333 SW Pine Street,
Tigard.
(45.4433, -122.7533)

Probable violation B.91:
Tree shows evidence
of contacting primary
conductors at
7175 SW Florence Lane,
Portland.
(45.4568, -122.7505)

Probable violation B.92:
Tree shows evidence
of contacting primary
conductors at
6571 SW Taylors Ferry
Road, Portland.
(45.4550, -122.7443)

Probable violation B.93:
Tree shows evidence
of contacting primary
conductors at
10112 SW 55th Avenue,
Portland.
(45.4524, -122.7333)

Probable violation B.94:
Tree shows evidence of contacting primary conductors at 10430 SW 55th Avenue, Portland.
(45.4502, -122.7333)

Probable violation B.95:
Two trees show evidence of contacting the primary conductor at 5741 SW Pasadena Drive, Portland.
(45.4457, -122.7359)

Probable violation B.96: Tree shows evidence of contacting primary conductors at 10805 SW 63rd Avenue, Portland. (45.4476, -122.7421)

Probable violation B.97: Multiple trees show evidence of contacting the primary conductor at the intersection of SW 62nd Drive and SW Huddleson Street, Portland. (45.4491, -122.7385)

Attachment A
OPUC Safety Report
E22-62R 3

Probable violation B.98:
Tree shows evidence of contacting primary conductors at 6220 SW Taylors Ferry Road, Portland.
(45.4545, -122.7411)

Probable violation B.99:
Tree shows evidence of contacting primary conductors at 9529 SW 62nd Drive, Portland.
(45.4571, -122.7391)

Attachment A
OPUC Safety Report
E22-62R 3

Probable violation B.100:
Tree shows evidence
of contacting primary
conductors at
9423 SW 62nd Drive,
Portland.
(45.4572, -122.7418)

Probable violation B.101:
Tree shows evidence
of contacting primary
conductors at
5301 SW Taylors Ferry
Road, Portland.
(45.4549, -122.7315)

Probable violation B.102:
Tree shows evidence
of contacting primary
conductors at
9711 SW 50th Avenue,
Portland.
(45.4552, -122.7285)

Probable violation B.103:
Tree shows evidence
of contacting primary
conductors at
8803 SW 51st Avenue,
Portland.
(45.4618, -122.7295)

Probable violation B.104:
Tree shows evidence
of contacting primary
conductors at
4509 SW Taylors Ferry
Road, Portland.
(45.4548, -122.7232)

Probable violation B.105:
Tree shows evidence
of contacting primary
conductors at
9314 SW 35th Avenue,
Portland.
(45.4584, -122.7133)

Attachment A
OPUC Safety Report
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Probable violation B.106:
Tree shows evidence
of contacting primary
conductors at
7639 SW Capitol Hill
Road, Portland.
(45.4688, -122.7000)

Probable violation B.107:
Tree shows evidence
of contacting primary
conductors at
2781 SW Troy Street,
Portland.
(45.4684, -122.7058)

Probable violation B.108:
Multiple trees show evidence of contacting the primary conductor at 4875 SW Schatz Road, Tualatin.
(45.3574, -122.7265)

Probable violation B.109:
Multiple trees show evidence of contacting the primary conductor at 22720 SW Stafford Road, Tualatin.
(45.3555, -122.7268)

Attachment A
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Probable violation B.110:
Tree shows evidence
of contacting primary
conductors at
23662 SW Stafford Road,
Tualatin.
(45.3486, -122.7348)

Probable violation B.111:
Tree shows evidence
of contacting primary
conductors at
4342 SW Kanan Drive,
Portland.
(45.4821, -122.7220)

Attachment A
OPUC Safety Report
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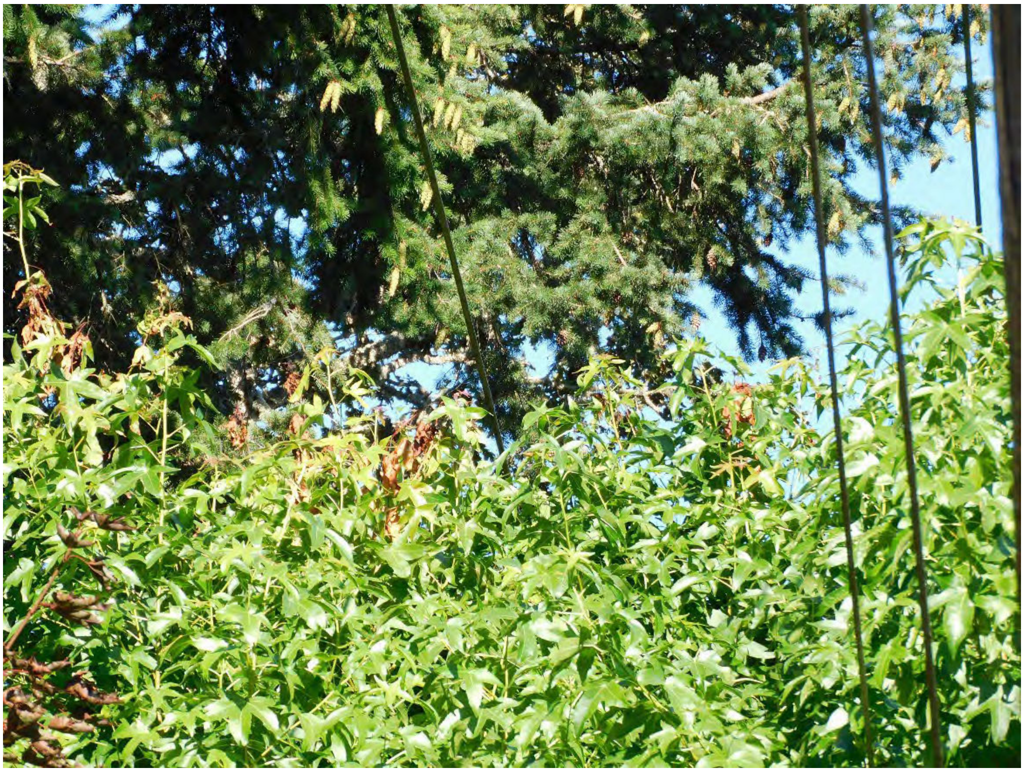
Probable violation B.112:
Tree shows evidence
of contacting primary
conductors at
1737 SW Canby Street,
Portland.
(45.4691, -122.6960)

Probable violation B.113:
Tree shows evidence
of contacting primary
conductors at
1615 SW Canby Street,
Portland.
(45.4691, -122.6946)



Probable violation B.114:
Tree shows evidence
of contacting primary
conductors at
5565 SW 88TH Avenue,
Portland.
(45.4801, -122.7677)

Probable violation B.115:
Tree shows evidence
of contacting primary
conductors at
20395 SW Stafford Street,
Tualatin.
(45.3722, -122.7051)

Probable violation B.116:
Tree shows evidence of
contacting primary
conductors at
2249 SW Borland Road,
Tualatin.
(45.3721, -122.6997)

Probable violation B.117: Multiple trees show evidence of contacting the primary conductor at 2175 SW Borland Road, Tualatin.
(45.3711, -122.6982)

Probable violation B.118: Tree shows evidence of contacting primary conductors at 2100 SW Borland Road, Tualatin.
(45.3691, -122.6972)

Probable violation B.119:
Tree shows evidence
of contacting primary
conductors at
1180 Rosemont Road,
West Linn.
(45.3698, -122.6483)

Probable violation B.120:
Tree shows evidence
of contacting primary
conductors at
18895 Old River Drive,
West Linn.
(45.3943, -122.6403)

Probable violation B.121:
Tree shows evidence of contacting primary conductors at 3188 Glenmorrie Drive, Lake Oswego.
(45.4066, -122.6553)

Probable violation B.122:
Multiple trees show evidence of contacting the primary conductor across 2980 Glenmorrie Drive, Lake Oswego.
(45.4054, -122.6547)

Probable violation B.123: Multiple trees show evidence of contacting the primary conductor at 2445 Glenmorrie Drive, Lake Oswego. (45.4031, -122.6571)

Probable violation B.124: Multiple trees show evidence of contacting the primary conductor at 2681 Greentree Road, Lake Oswego. (45.4027, -122.7039)

Attachment A
OPUC Safety Report
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Probable violation B.125:
Tree shows evidence
of contacting primary
conductors at
2991 Glen Haven Road,
Lake Oswego
(45.4021, -122.7073)

Probable violation B.126:
Tree shows evidence
of contacting primary
conductors at the
intersection of Woodside
Circle and Deerbrush
Avenue, Lake Oswego
(45.3962, -122.7218)

Attachment A
OPUC Safety Report
E22-62R 4

Probable violation B.127: Tree shows evidence of contacting primary conductors at the intersection of SE Emerald Drive and SE Jennings Avenue, Portland. (45.3948, -122.6041)

Probable violation B.128: Two trees show evidence of contacting the primary conductor at 5323 SE Jennings Avenue, Portland. (45.3928, -122.6088)

Probable violation B.129:
Multiple trees show evidence of contacting the primary conductor at 4531 SE Jennings Avenue, Portland.
(45.3905, -122.6158)

Probable violation B.130:
Tree shows evidence of contacting primary conductors at 4215 SE Jennings Avenue, Portland.
(45.3891, -122.6195)

Attachment A
OPUC Safety Report
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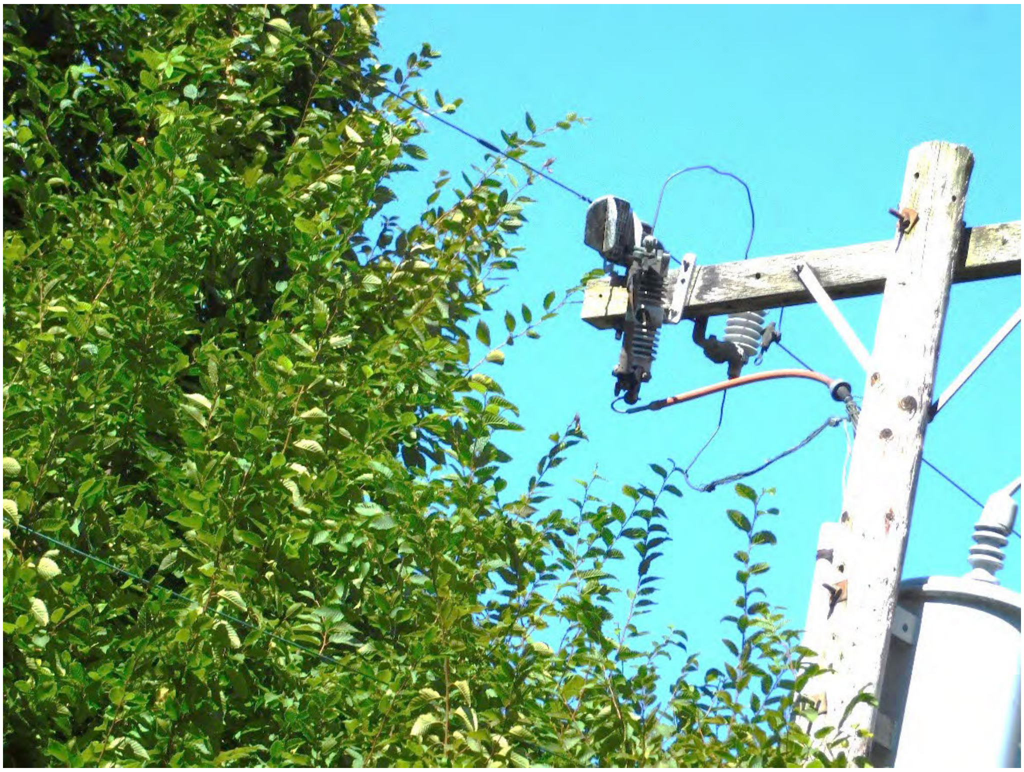
Probable violation B.131: Tree shows evidence of contacting primary conductors at 18535 SE River Road, Portland. (45.3884, -122.6146)

Probable violation B.132: Tree shows evidence of contacting primary conductors at 5035 SE Glen Echo Avenue, Portland. (45.3830, -122.6112)

Attachment A
OPUC Safety Report
E22-62R 4



Probable violation B.133:
Tree shows evidence
of contacting primary
conductors at
4785 SE La Cour Court,
Portland.
(45.3815, -122.6148)

Probable violation B.134:
Tree shows evidence
of contacting primary
conductors at
4289 SE Manewal Lane,
Portland.
(45.3823, -122.6188)

Probable violation B.135: Multiple trees show evidence of contacting the primary conductor at 19555 River Road, Portland. (45.3806, -122.6069)

Probable violation B.136: Tree shows evidence of contacting primary conductors at 19575 River Road, Portland. (45.3788, -122.6084)

Probable violation B.137: Multiple trees show evidence of contacting the primary conductor at 17415 SE River Road, Portland.
(45.3968, -122.6274)

Probable violation B.138: Tree shows evidence of contacting primary conductors at 2911 SE Laurelwood Drive, Portland.
(45.3987, -122.6326)

Probable violation B.139: Tree shows evidence of contacting primary conductors at 2850 SE Cooke Road, Portland. (45.3993, -122.6338)

Probable violation B.140: Multiple trees show evidence of contacting the primary conductor at 2762 SE Vineyard Way, Portland. (45.4007, -122.6346)

Probable violation B.141: Multiple trees show evidence of contacting the primary conductor at the intersection of SE River Road and SE Vineyard Way, Portland. (45.4011, -122.6334)

Probable violation B.142: Tree shows evidence of contacting primary conductors at 2420 SE Mulberry Drive, Portland. (45.4008, -122.6380)

Probable violation B.143
Multiple trees show evidence of contacting the primary conductor at 2611 SE Tarbell Avenue, Portland.
(45.4047, -122.6371)

Probable violation B.144:
Multiple trees show evidence of contacting the primary conductor at 16205 SE River Road, Portland.
(45.4056, -122.6405)

Attachment A
OPUC Safety Report
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Probable violation B.145:
Tree shows evidence
of contacting primary
conductors at
15695 SE Dana Avenue,
Portland.
(45.4093, -122.6489)

Probable violation B.146:
Tree shows evidence
of contacting primary
conductors at
14325 SE River Road,
Portland.
(45.4188, -122.6457)

Attachment A
OPUC Safety Report
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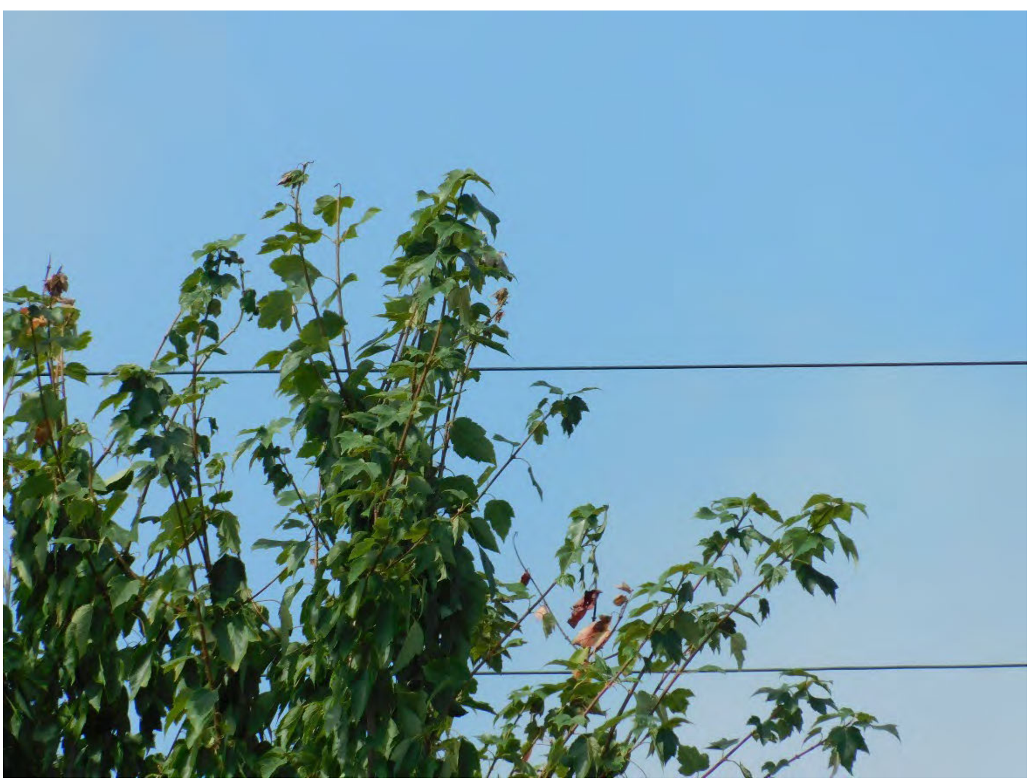
Probable violation B.147:
Tree shows evidence
of contacting primary
conductors at
16417 SE McLoughlin
Blvd., Portland.
(45.4039, -122.6229)



Probable violation B.148:
Tree shows evidence
of contacting primary
conductors at
15117 SE McLoughlin
Blvd., Portland.
(45.4135, -122.6303)

Attachment A
OPUC Safety Report
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Probable violation B.149: Multiple trees show evidence of contacting the primary conductor at 14585 SE McLoughlin Blvd., Portland (45.4176, -122.6328)

Probable violation B.150: Tree shows evidence of contacting primary conductors at 2096 SE Pinelane Street, Portland. (45.4195, -122.6418)

Attachment A
OPUC Safety Report
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Probable violation B.151:
Tree shows evidence
of contacting primary
conductors at
15716 SE Creswain
Avenue, Portland.
(45.4094, -122.6400)

Probable violation B.152:
Tree shows evidence
of contacting primary
conductors at
2340 SE Swain Avenue,
Portland.
(45.4073, -122.6402)

Attachment A
OPUC Safety Report
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Probable violation B.153:
Tree shows evidence
of contacting primary
conductors at
16217 SE River Road,
Portland.
(45.4053, -122.6399)

Probable violation B.154:
Tree shows evidence
of contacting primary
conductors at
2710 SE Concord Road,
Portland.
(45.4063, -122.6349)

Probable violation B.155:
Tree shows evidence of contacting primary conductors at
2800 SE Concord Road, Portland.
(45.4067, -122.6336)

Probable violation B.156:
Tree shows evidence of contacting primary conductors at
3310 SE Westview Road, Portland.
(45.4060, -122.6283)

Probable violation B.157:
Tree shows evidence
of contacting primary
conductors at
15103 SE Kellogg
Avenue, Portland.
(45.4137, -122.6286)

Probable violation B.158:
Tree shows evidence
of contacting primary
conductors at
15016 SE Oatfield Road,
Portland.
(45.4141, -122.6242)

Probable violation B.159:
Two trees show evidence of contacting the primary conductor at
4404 SE Hill Road, Portland.
(45.4189, -122.6173)

Probable violation B.160:
Tree shows evidence of contacting primary conductors at 4912 SE Hill Road, Portland.
(45.4189, -122.6124)

Attachment A
OPUC Safety Report
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Probable violation B.161:
Tree shows evidence
of contacting primary
conductors across from
5201 SE Hill Road,
Portland.
(45.4170, -122.6097)

Probable violation B.162:
Tree shows evidence
of contacting primary
conductors at
15318 SE Outfield Road,
Portland.
(45.4117 , -122.6217)

Attachment A
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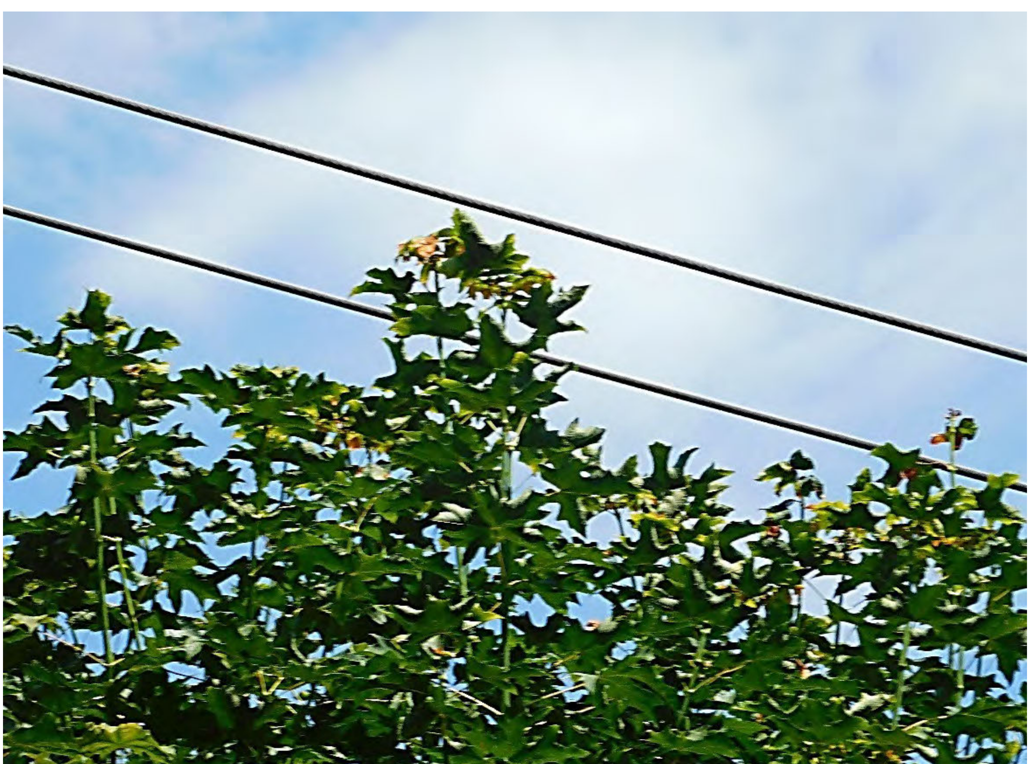
Probable violation B.163:
Multiple trees show evidence of contacting the primary conductor at 3950 SE View Acres Road, Portland.
(45.4131, -122.6216)

Probable violation B.164:
Tree shows evidence of contacting primary conductors at 4550 SE View Acres Road, Portland.
(45.4163, -122.6171)

Probable violation B.165: Multiple trees show evidence of contacting the primary conductor at 4818 SE View Acres Road, Portland.
(45.4189, -122.6133)

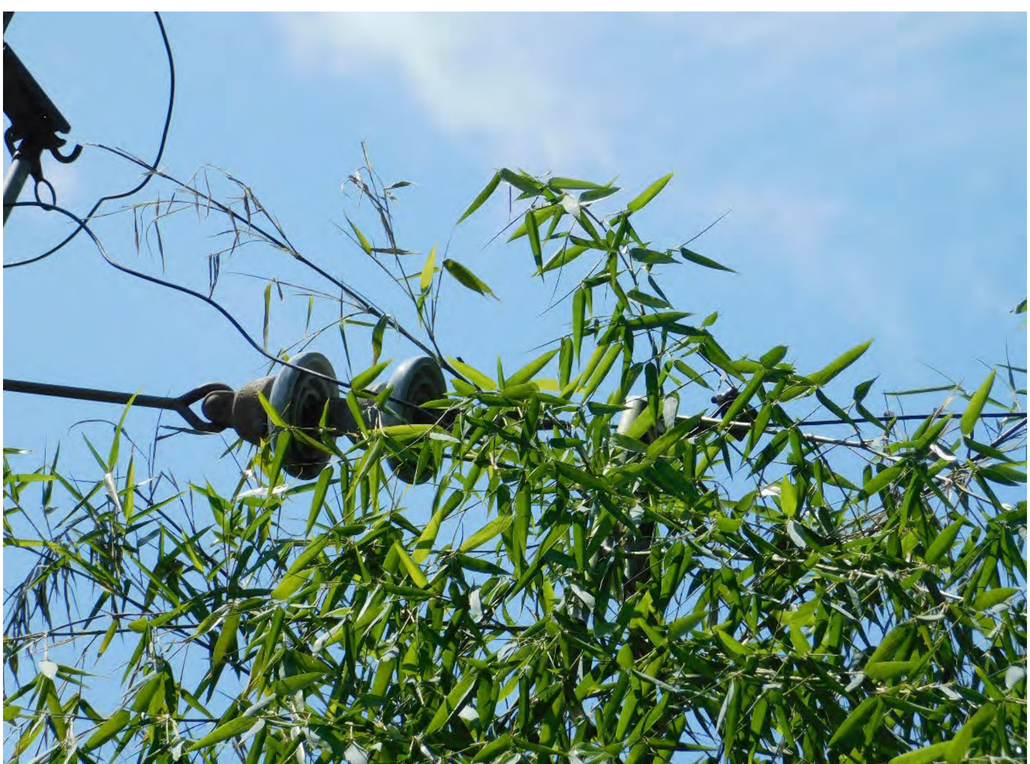


Probable violation B.166: Multiple trees show evidence of contacting the primary conductor across from 5904 SE Thiessen Road, Portland.
(45.4162, -122.6022)

Probable violation B.167: Tree shows evidence of contacting primary conductors at the intersection of SE Aldercrest Road and SE Thiessen Road, Portland. (45.4163, -122.6000)

Probable violation B.168: Tree shows evidence of contacting primary conductors at 6050 SE Alderhill Loop, Portland. (45.4171, -122.6004)

Probable violation B.169:
Tree shows evidence of contacting primary conductors at 6593 SE Thiessen Road, Portland.
(45.4162, -122.5962)



Probable violation B.170:
Multiple trees show evidence of contacting the primary conductor at 16060 SE Brenda Avenue, Portland.
(45.4066, -122.5849)

Attachment A
OPUC Safety Report
E22-62R 4

Probable violation B.171:
Multiple trees show evidence of contacting the primary conductor at 16704 SE Oatfield Road, Portland.
(45.4024, -122.6092)

Probable violation B.172:
Tree shows evidence of contacting primary conductors at
15106 SE Oatfield Road, Portland.
(45.4138, -122.6239)

Attachment A
OPUC Safety Report
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Probable violation B.173:
Tree shows evidence
of contacting primary
conductors at
14928 SE Oatfield Road,
Portland.
(45.4146, -122.6248)

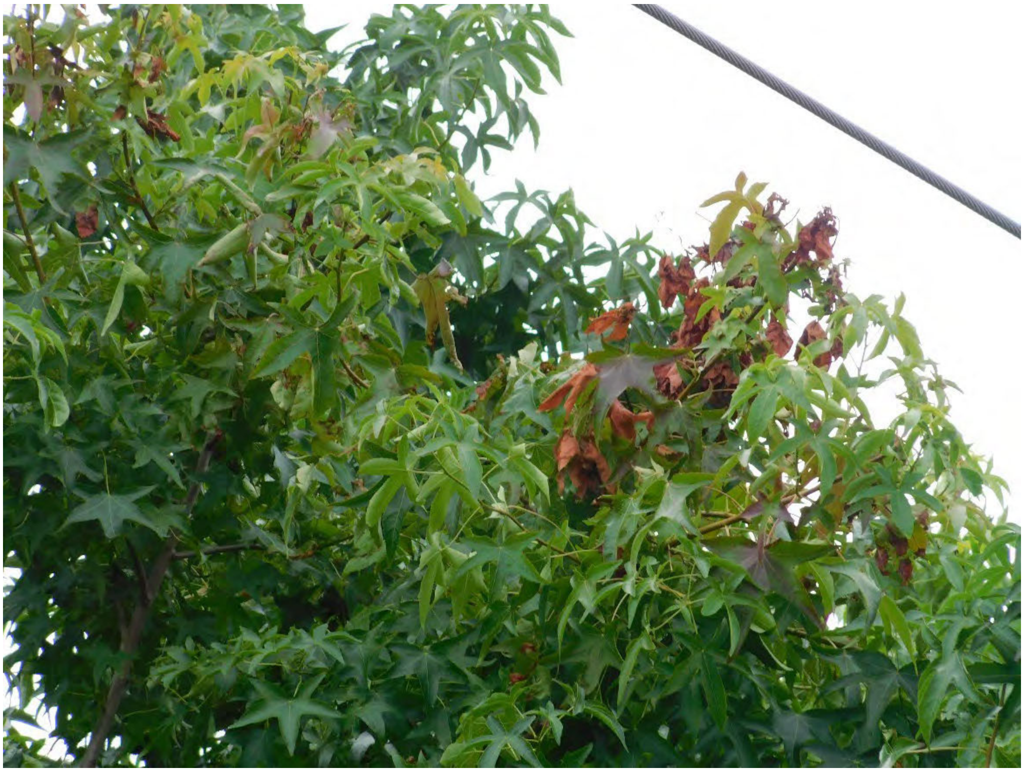
Probable violation B.174:
Tree shows evidence
of contacting primary
conductors at
13001 SE Rusk Road,
Portland.
(45.4289, -122.6014)

Probable violation B.175: Multiple trees show evidence of contacting the primary conductor at 7919 SE Sunnyside Drive, Portland.
(45.4337, -122.5807)

Probable violation B.176: Tree shows evidence of contacting primary conductors at 7506 SE Sunnyside Drive, Portland.
(45.4333, -122.5865)

Probable violation B.177:
Tree shows evidence
of contacting primary
conductors at
12145 SE 80th Avenue,
Portland.
(45.4353, -122.5807)

Probable violation B.178:
Tree shows evidence
of contacting primary
conductors at
7816 SE Stephanie Court,
Portland.
(45.4379, -122.5838)



Probable violation B.179: Multiple trees show evidence of contacting the primary conductor at 11802 SE Fuller Road, Portland.
(45.4363, -122.5850)

Probable violation B.180: Tree shows evidence of contacting primary conductors at 8010 SE McBride Street, Portland.
(45.4358, -122.5814)

Probable violation B.181:
Multiple trees show evidence of contacting the primary conductor at 11430 SE Fuller Road, Portland.
(45.4397, -122.5828)

Probable violation B.182:
Multiple trees show evidence of contacting the primary conductor at 11200 SE Fuller Road, Portland.
(45.4418, -122.5817)

Probable violation B.183: Two trees show evidence of contacting the primary conductor across from 11101 SE Fuller Road, Portland.
(45.4426, -122.5813)

Probable violation B.184: Tree shows evidence of contacting primary conductors at 10920 SE 72nd Avenue, Portland.
(45.4438, -122.5893)

Probable violation B.185: Multiple trees show evidence of contacting the primary conductor at 10852 SE 7th Avenue, Portland.
(45.4446, -122.5891)

Probable violation B.186: Tree shows evidence of contacting primary conductors at 7411 SE Monroe Street, Portland.
(45.4448, -122.5870)

Probable violation B.187:
Tree shows evidence
of contacting primary
conductors at
6710 SE Catalina Lane,
Portland.
(45.4426 ,-122.5941)

Probable violation B.188:
Tree shows evidence
of contacting primary
conductors at
6625 SE Charles Street,
Portland.
(45.4419, -122.5955)

Attachment A
OPUC Safety Report
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Probable violation B.189:
Tree shows evidence
of contacting primary
conductors at
7245 SE Harmony Drive,
Portland.
(45.4411, -122.5883)

Probable violation B.190:
Tree shows evidence
of contacting primary
conductors at
7643 SE Harmony Drive,
Portland.
(45.4411, -122.5844)

Probable violation B.191: Tree shows evidence of contacting primary conductors at 6306 SE Cedarcrest Drive, Portland.
(45.4329, -122.5983)

Probable violation B.192: Multiple trees show evidence of contacting the primary conductor the intersection of SE Railroad Avenue and SE Harmony Road, Portland.
(45.4324, -122.5997)

Probable violation B.193:
Tree shows evidence of contacting primary conductors at 11415 SE Stanley Avenue, Portland.
(45.4403, -122.6037)

Probable violation B.194:
Multiple spans show evidence of multiple trees contacting the primary conductor on SE Railroad Avenue, Portland.
(45.4362, -122.6096) to (45.4430, -122.6236)

Probable violation B.195:
Tree shows evidence
of contacting primary
conductors at
5411 SE Monroe Street,
Portland.
(45.4448, -122.6076)

Probable violation B.196:
Tree shows evidence
of contacting primary
conductors at
4786 SE Jackson Street,
Portland.
(45.4458, -122.6135)

Probable violation B.197:
Tree shows evidence of contacting primary conductors at 3902 SE King Street, Portland.
(45.4480, -122.6229)

Probable violation B.198:
Multiple trees show evidence of contacting the primary conductor at 10264 SE 37th Avenue, Portland.
(45.4491, -122.6247)

Probable violation B.199:
Two trees show evidence of contacting the primary conductor at 9922 SE 37th Avenue, Portland.
(45.4511, -122.6247)

Probable violation B.200:
Tree shows evidence of contacting primary conductors at 4180 SE Harvey Court, Portland.
(45.4513, -122.6205)

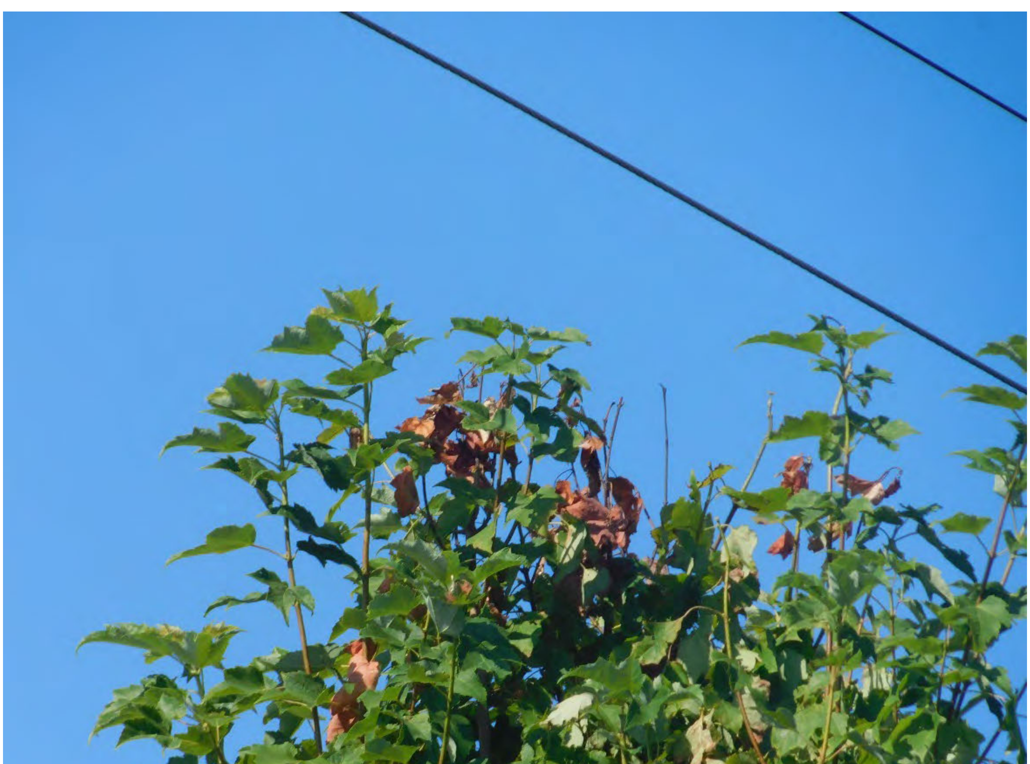
Probable violation B.201:
Tree shows evidence
of contacting primary
conductors at
4016 SE Rosewell Street,
Portland.
(45.4584, -122.6220)

Probable violation B.202:
Multiple trees show
evidence of contacting
the primary conductor at
8607 SE 29th Avenue,
Portland.
(45.4605, -122.6330)

Probable violation B.203:
Tree shows evidence of contacting primary conductors at 8607 SE 29th Avenue, Portland.
(45.4573, -122.6328)

Probable violation B.204:
Multiple trees show evidence of contacting the primary conductor at 9029 SE 29th Avenue, Portland.
(45.4552, -122.6327)

Probable violation B.205:
Tree shows evidence
of contacting primary
conductors at
9323 SE 29th Avenue,
Portland.
(45.4529, -122.6327)



Probable violation B.206:
Tree shows evidence
of contacting primary
conductors at
5707 SE 92nd Avenue,
Portland.
(45.4813, -122.5692)

Probable violation B.207: Multiple trees show evidence of contacting the primary conductor at 8940 SE Reedway Street, Portland.
(45.4813, -122.5703)

Probable violation B.208: Multiple trees show evidence of contacting the primary conductor at 3223 SE 92nd Avenue, Portland.
(45.4988, -122.5684)

Attachment A
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Probable violation B.209:
Tree shows evidence
of contacting primary
conductors at
2626 SE 92nd Avenue,
Portland.
(45.5031, -122.5685)

Probable violation B.210:
Tree shows evidence of
contacting primary
conductors across from
4035 SE 82nd Avenue,
Portland.
(45.4933, -122.5787)

Probable violation B.211:
Multiple trees show evidence of contacting the primary conductor across from 8230 SE Liebe Steet, Portland.
(45.4870, -122.5782)

Probable violation B.212:
Tree shows evidence of contacting primary conductors at the intersection of SE Liebe Street and SE 86th Court, Portland.
(45.4870, -122.5741)

Probable violation B.213: Tree shows evidence of contacting primary conductors at the intersection of SE Raymond Court and Southeast 86TH Court, Portland.
(45.4858, -122.5741)

Probable violation B.214: Tree shows evidence of contacting primary conductors at 7123 SE Knight Street, Portland.
(45.4803, -122.5898)

Attachment A
OPUC Safety Report
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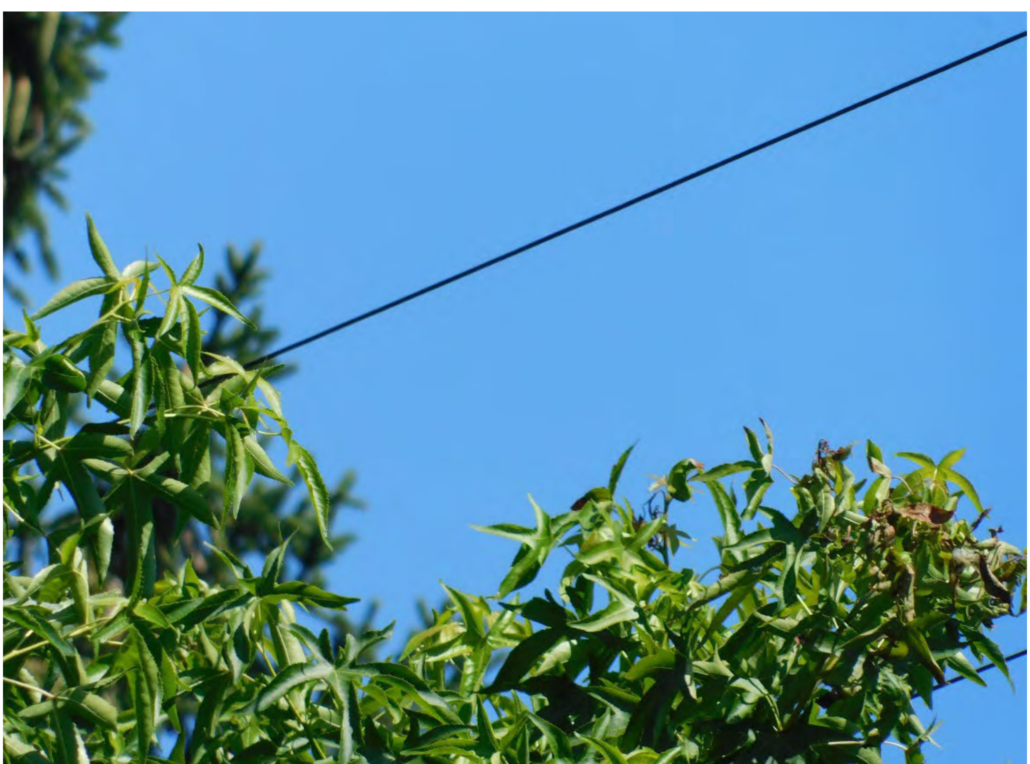
Probable violation B.215:
Tree shows evidence of contacting primary conductors at 7005 SE Mitchell Street, Portland.
(45.4857, -122.5912)

Probable violation B.216:
Tree shows evidence of contacting primary conductors at 5905 SE Insley Street, Portland.
(45.4840, -122.6028)

Probable violation B.217:
Tree shows evidence of contacting primary conductors at 5519 SE Insley Street, Portland.
(45.4839, -122.6061)

Probable violation B.218:
Multiple trees show evidence of contacting the primary conductor behind 5218 SE Tolman Street, Portland.
(45.4770, -122.6078)

Probable violation B.219:
Tree shows evidence of contacting primary conductors at 6232 SE 47th Avenue, Portland.
(45.4771, -122.6143)

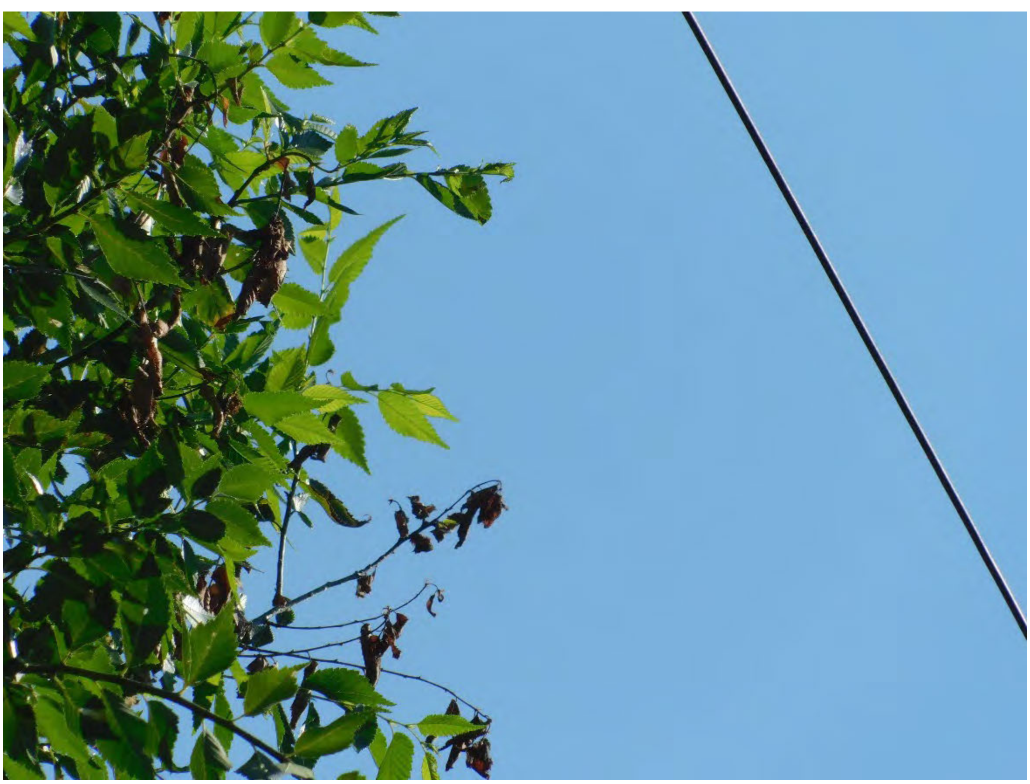


Probable violation B.220:
Tree shows evidence of contacting primary conductors at 6136 SE 46th Avenue, Portland.
(45.4778, -122.6153)

Probable violation B.221:
Tree shows evidence of contacting primary conductors at 3808 SE Henry Street, Portland.
(45.4762, -122.6233)

Probable violation B.222:
Multiple trees show evidence of contacting the primary conductor at 6025 SE 34th Avenue, Portland.
(45.4789 -122.6283)

Probable violation B.223:
Tree shows evidence
of contacting primary
conductors at
3817 SE Tolman Street,
Portland.
(45.4771, -122.6232)



Probable violation B.224:
Tree shows evidence
of contacting primary
conductors at
5835 SE 40th Avenue,
Portland.
(45.4800, -122.6221)

Attachment A
OPUC Safety Report
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Probable violation B.225:
Tree shows evidence
of contacting primary
conductors at
5730 SE 41st Avenue,
Portland.
(45.4807, -122.6204)

Probable violation B.226:
Tree shows evidence
of contacting primary
conductors at
4205 SE Romana Street,
Portland.
(45.4807, -122.6194)

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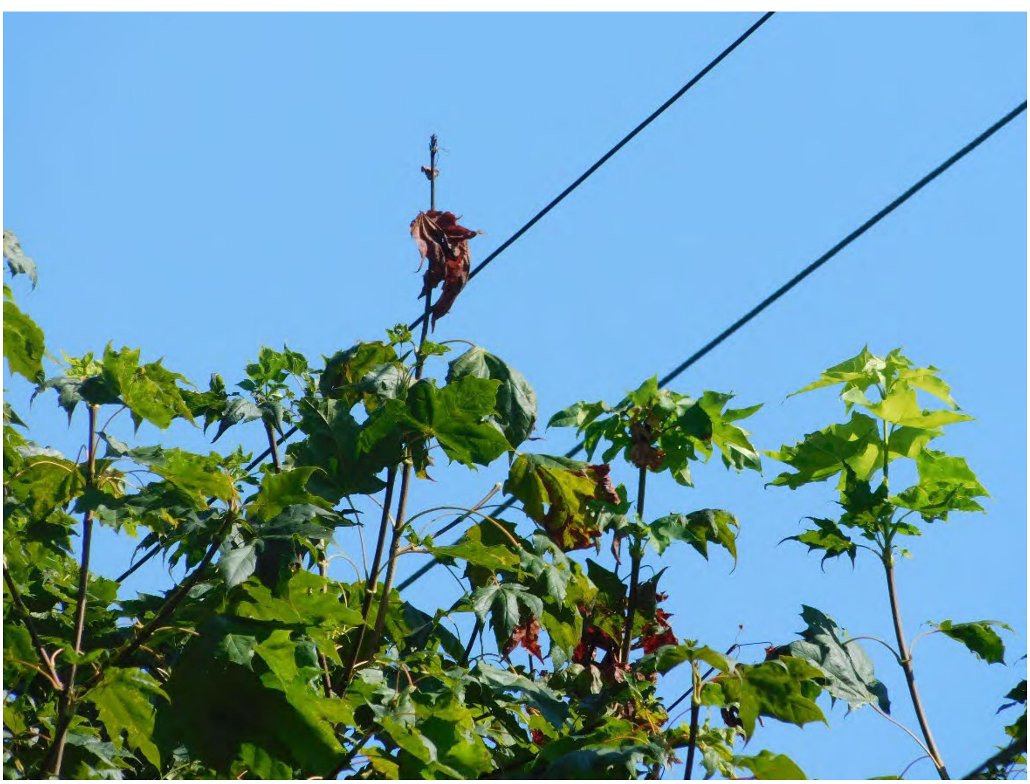
OPUC Safety Report
E22-62R 4

Probable violation B.227: Multiple trees show evidence of contacting the primary conductor at 4507 SE Romana Street, Portland.
(45.4807, -122.6163)



Probable violation B.228: Tree shows evidence of contacting primary conductors across from 5609 SE 48th Avenue, Portland.
(45.4818, -122.6133)

Probable violation B.229:
Tree shows evidence
of contacting primary
conductors at
5637 SE 45th Avenue,
Portland.
(45.4814, -122.6167)

Probable violation B.230:
Tree shows evidence
of contacting primary
conductors at
5233 SE 38th Avenue,
Portland.
(45.4848, -122.6232)

Probable violation B.231: Multiple trees show evidence of contacting the primary conductor at 4814 SE 28th Avenue, Portland.
(45.4881, -122.6375)

Probable violation B.232: Multiple trees show evidence of contacting the primary conductor at 6040 SE 32nd Avenue, Portland.
(45.4787, -122.6304)

Probable violation B.233: Multiple trees show evidence of contacting the primary conductor at 6121 SE 32nd Avenue, Portland.
(45.4780, -122.6311)

Probable violation B.234: Tree shows evidence of contacting primary conductors on SW Ek Road, West Linn.
(45.3670, -122.7054)

Probable violation B.235:
Tree shows evidence
of contacting primary
conductors at
797 SW Borland Road,
West Linn.
(45.3556, -122.6847)

Probable violation B.236:
Tree shows evidence
of contacting primary
conductors at
2665 SW Schaeffer Road,
West Linn.
(45.3492, -122.7041)

Attachment A
OPUC Safety Report
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Probable violation B.237:
Tree shows evidence of contacting primary conductors on SW Turner Road, West Linn.
(45.3592, -122.6954)

Probable violation B.238:
Two trees show evidence of contacting the primary conductor on SW Turner Road, West Linn.
(45.3586, -122.6936)

Probable violation B.239:
Tree shows evidence of contacting primary conductors at 1085 SW Willamette Falls Drive, West Linn. (45.3445, -122.6678)

Probable violation B.240:
Two trees show evidence of contacting the primary conductor at 1208 SW Willamette Falls Drive, West Linn. (45.3439, -122.6651)

Attachment A
OPUC Safety Report
E22-62R 4

Probable violation B.241:
Two trees show evidence of contacting the primary conductor on
Dollar Street, West Linn.
(45.3447, -122.6589)

Probable violation B.242:
Tree shows evidence of contacting primary conductors on
Dollar Street, West Linn.
(45.3451, -122.6603)

Probable violation B.243: Tree shows evidence of contacting primary conductors at 1315 Dollar Street, West Linn. (45.3460, -122.6630)

Probable violation B.244: Multiple trees show evidence of contacting the primary conductor on Volpp Street, West Linn. (45.3393, -122.6502)

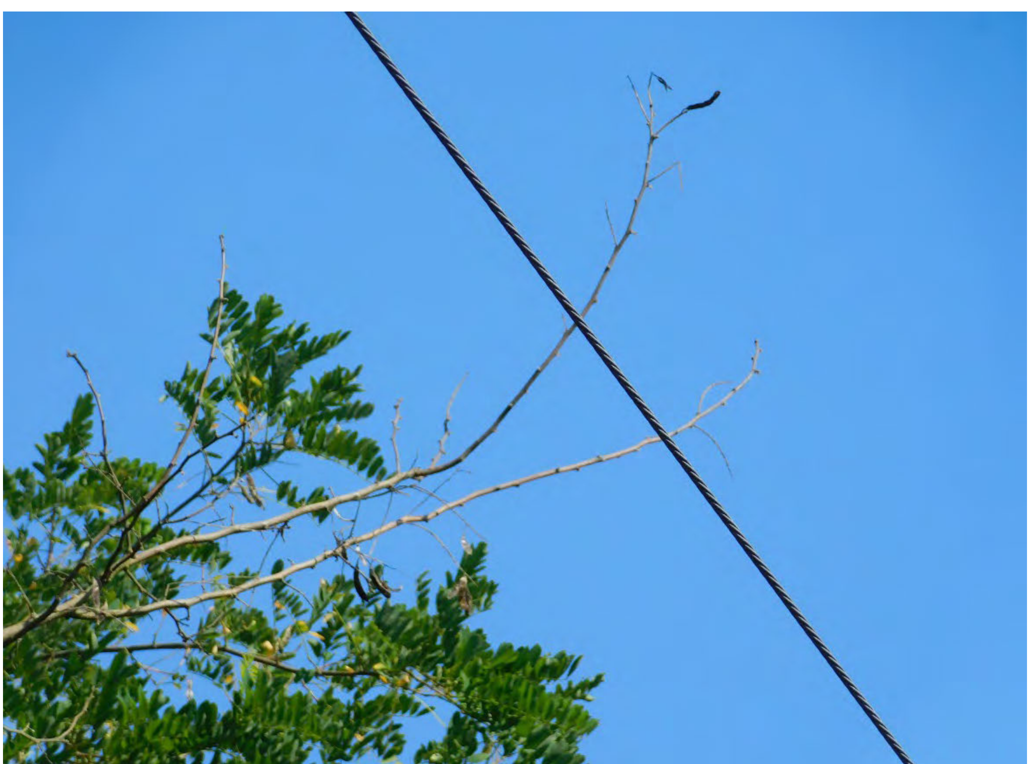
Probable violation B.245: Two trees show evidence of contacting the primary conductor on 4th Avenue, West Linn. (45.3456, -122.6396)

Probable violation B.246: Tree shows evidence of contacting primary conductors on 5th Avenue, West Linn. (45.3451, -122.6470)

Attachment A
OPUC Safety Report
E22-62R 4

Probable violation B.247:
Tree shows evidence
of contacting primary
conductors on
11th Street, West Linn.
(45.3431, -122.6519)

Probable violation B.248:
Tree shows evidence
of contacting primary
conductors at
2266 Cloverdale Drive SE,
Jefferson.
(44.8233, -123.0150)



Probable violation B.249:
Tree shows evidence
of contacting primary
conductors at
7715 5th Street SE, Turner.
(44.8434, -122.9560)

Probable violation B.250:
Tree shows evidence
of contacting primary
conductors at
5335 Chicago Street SE,
Turner.
(44.8427, -122.9507)

Probable violation B.251:
Tree shows evidence
of contacting primary
conductors at
5255 Boise Street SE,
Turner.
(44.8436, -122.9522)

Probable violation B.252:
Tree shows evidence of contacting primary conductors at 6724 Mill Creek Road SE, Turner.
(44.8387, -122.9233)

Probable violation B.253:
Multiple trees show evidence of contacting primary conductors at 7937 Pine Tree Lane SE, Turner.
(44.8398, -122.9309)

Attachment A
OPUC Safety Report
E22-62R 5

Probable violation B.254: Multiple trees show evidence of contacting primary conductors at 7838 Pine Tree Lane SE, Turner.
(44.8409, -122.9293)

Probable violation B.255: Tree shows evidence of contacting primary conductors at 7472 Mill Creek Road SE, Aumsville.
(44.8389, -122.9069)

Attachment A
OPUC Safety Report
E22-62R 5

Probable violation B.256:
Multiple trees show evidence of contacting primary conductors at 7632 Witzel Road SE, Turner.
(44.8450, -122.9399)

Probable violation B.257:
Tree shows evidence of contacting primary conductors at the intersection of Gath Road SE and Chrisman Lane Se, Salem.
(44.8726, -122.9530)

Probable violation B.258:
Tree shows evidence of contacting primary conductors at 1128 Lancaster Drive NE, Salem.
(44.9439, -122.9833)

Probable violation B.259:
Multiple trees show evidence of contacting primary conductors at 3925 Lancaster Drive NE, Salem.
(44.9762, -122.9836)

Probable violation B.260: Multiple trees show evidence of contacting primary conductors at 4579 Lancaster Drive NE, Salem.
(44.9872, -122.9833)

Probable violation B.261: Tree shows evidence of contacting primary conductors at 117 Bayview Way NE, Salem.
(44.9281, -122.9674)

Probable violation B.262:
Tree shows evidence
of contacting primary
conductors at the
intersection of Center
Street NE and Cordon
Road NE, Salem.
44.9395, -122.9598)

Probable violation B.263:
Tree shows evidence
of contacting primary
conductors at
4507 Blackberry Lane NE,
Salem.
(44.9733, -122.9731)

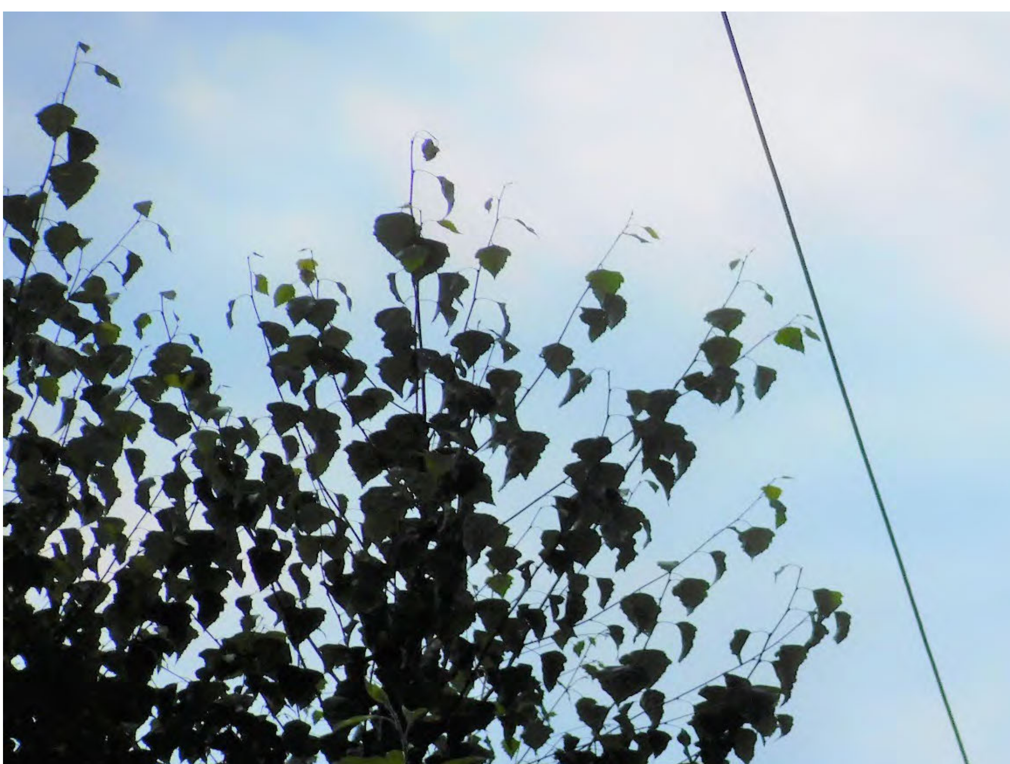
Probable violation B.264:
Tree shows evidence of contacting primary conductors at the intersection of 45th Avenue NE and Herrin Road NE, Salem.
(44.9771, -122.9731)

Probable violation B.265:
Two trees show evidence of contacting primary conductors at 4582 Herrin Road NE, Salem.
(44.9771, -122.9709)

Probable violation B.266:
Tree shows evidence of contacting primary conductors at 4128 Cordon Road NE, Salem.
(44.9789, -122.9567)

Probable violation B.267:
Tree shows evidence of contacting primary conductors at 4410 Cordon Road NE, Salem.
(44.9854, -122.9552)

Probable violation B.268:
Tree shows evidence
of contacting primary
conductors at
3507 Middle Grove Dr
NE, Salem.
(44.9703, – 122.9616)



Probable violation B.269:
Tree shows evidence
of contacting primary
conductors at
8712 Boulder Ridge Court,
Salem.
(44.9257, -122.8842)

Probable violation B.270:
Tree shows evidence
of contacting primary
conductors at
1291 62nd Avenue SE,
Salem.
(44.9137, -122.9339)

Probable violation B.271:
Tree shows evidence
of contacting primary
conductors at
7373 Conifer Road NE,
Salem.
44.9458, -122.9103)

Probable violation B.272:
Tree shows evidence
of contacting primary
conductors at
6903 Sunnyview Road NE,
Salem.
(44.9565, -122.9205)

Probable violation B.273:
Tree shows evidence
of contacting primary
conductors across from
10844 Kaufman Road NE,
Silverton.
(44.9697, -122.8388)

Probable violation B.274:
Two trees show evidence of contacting primary conductors at
110 Smith Street, Silverton.
(44.9965, -122.7760)

Probable violation B.275:
Two trees show evidence of contacting primary conductors at
840 Barger Street,
Silverton, Silverton.
(44.9973, -122.7788)

Attachment A
OPUC Safety Report
E22-62R 5

Probable violation B.276:
Tree shows evidence
of contacting primary
conductors at
6043 Sunnyview Road NE,
Salem.
(44.9549, -122.9372)

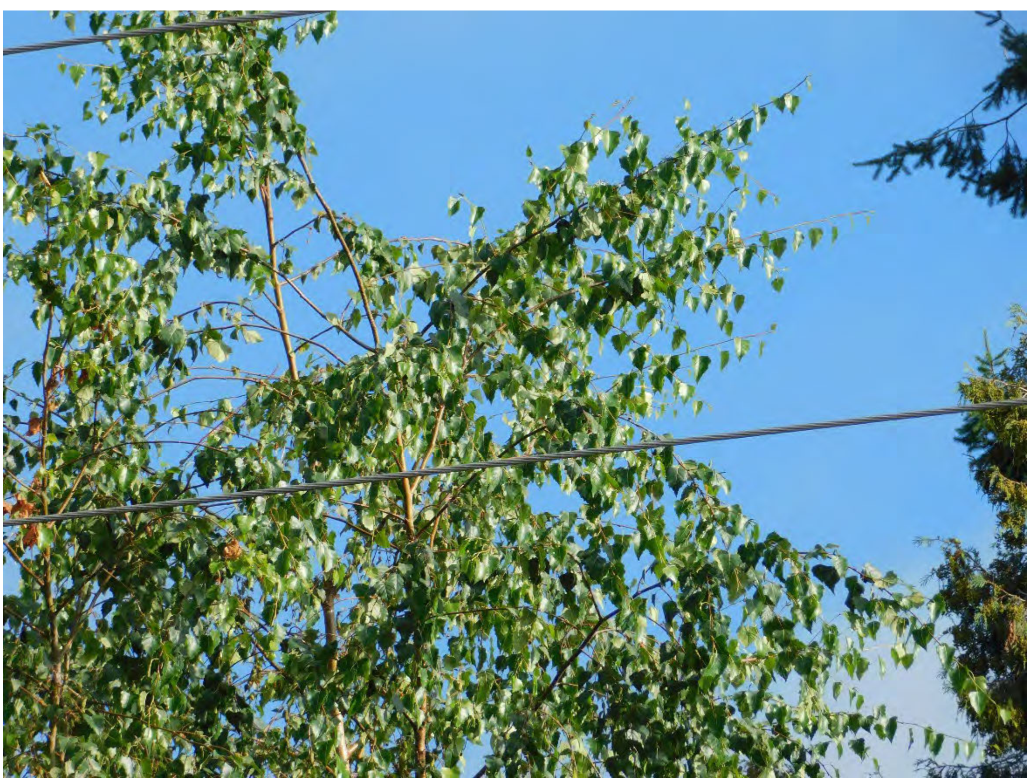
Probable violation B.277:
Tree shows evidence
of contacting primary
conductors at
15010 South Maple Grove
Road, Molalla.
(45.0411, -122.5579)
HFRZ

Attachment A
OPUC Safety Report
E22-62R 5

Probable violation B.278:
Tree shows evidence
of contacting primary
conductors at
11151 South Wildcat
Road, Molalla.
(45.0783, -122.6367)
HFRZ

Probable violation B.279:
Tree shows evidence
of contacting primary
conductors at
4783 38th Avenue NE,
Salem.
(44.9926, -122.9864)

Probable violation B.280:
Tree shows evidence of contacting primary conductors at 4565 Hazelgreen Road NE, Salem.
(45.0046, -122.9677)



Probable violation B.281:
Tree shows evidence of contacting primary conductors at 4753 Hazelgreen Road NE, Salem.
(45.0046, -122.9637)

Probable violation B.282:
Tree shows evidence
of contacting primary
conductors at
5790 Lake Labish Road,
Salem.
(45.0057, -122.9617)

Probable violation B.283:
Tree shows evidence
of contacting primary
conductors at
5995 Lake Labish Road,
Salem.
(45.0078, -122.9617)

Attachment A
OPUC Safety Report
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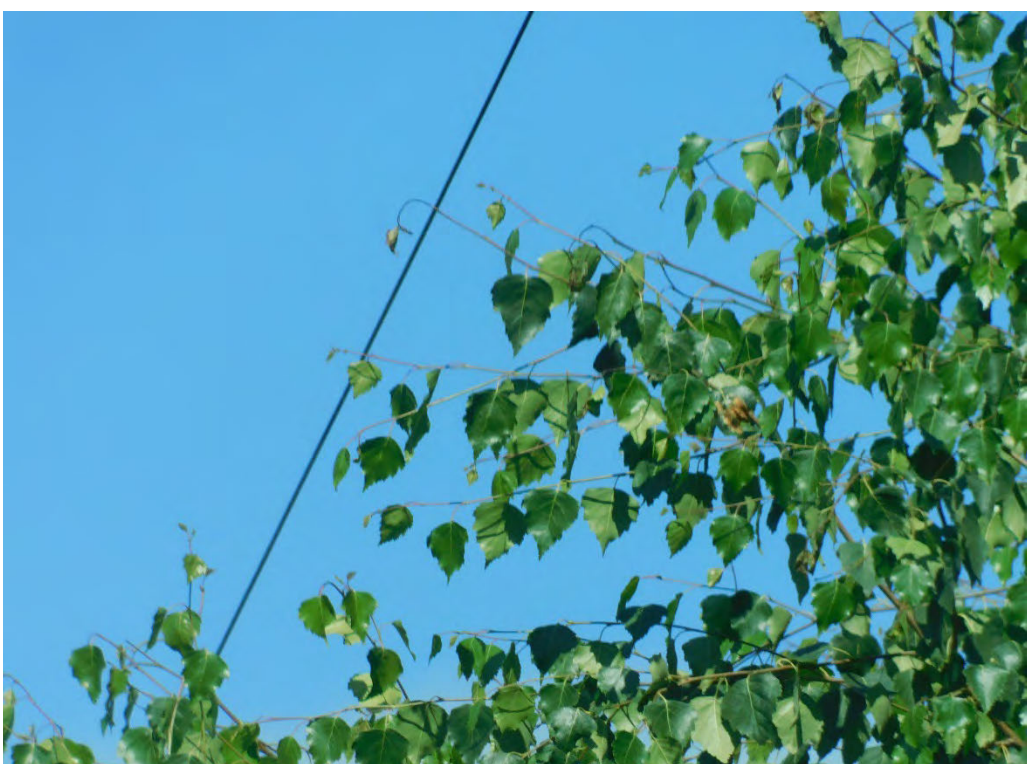
Probable violation B.284:
Tree shows evidence
of contacting primary
conductors at
7215 Lakeside Drive NE,
Salem.
(45.0231, -122.9612)

Probable violation B.285:
Tree shows evidence
of contacting primary
conductors at
7256 Lakeside Drive NE,
Salem.
(45.0236, -122.9573)

Probable violation B.286:
Tree shows evidence
of contacting primary
conductors at
7296 54th Avenue NE,
Salem.
(45.0243, -122.9513)



Probable violation B.287:
Tree shows evidence
of contacting primary
conductors at
4267 Scott Avenue NE,
Salem.
(45.0202, -122.9734)

Probable violation B.288:
Two trees show evidence
of contacting primary
conductors at
4433 Dover Avenue NE,
Salem.
(45.0185, -122.9718)

Probable violation B.289:
Tree shows evidence
of contacting primary
conductors at
4251 Webb Avenue NE,
Salem.
(45.0177, -122.9753)

Probable violation B.290: Two trees in an orchard, **creating a hazard**, show evidence of contacting the primary conductor across from 6060 Brooklake Road NE, Salem.
(45.0417, -122.9362)

Probable violation B.291: Tree shows evidence of contacting primary conductors at
6361 Brooklake Road NE, Salem.
(45.0402, -122.9309)

Attachment A
OPUC Safety Report
E22-62R 5

Probable violation B.292:
Tree shows evidence
of contacting primary
conductors at
6601 Brooklake Road NE,
Salem.
(45.0387, -122.9256)

Probable violation B.293:
Tree shows evidence
of contacting primary
conductors at
8646 Lakeside Drive NE,
Salem.
(45.0427, -122.9313)

Probable violation B.294:
Tree shows evidence of contacting primary conductors across from 9952 Nusom Road, NE, Salem.
(45.0344, -122.8566)

Probable violation B.295:
Tree shows evidence of contacting primary conductors at 990 Taylor Street, Mount Angel.
(45.0689, -122.7883)

Probable violation B.296:
Tree shows evidence
of contacting primary
conductors at
110 Lincoln Street, Mount
Angel.
(45.0677, -122.8022)

Probable violation B.297:
Tree shows evidence
of contacting primary
conductors across from
9344 Mount Angel/Gervais
Road, Gervais.
(45.0932, -122.8710)

Attachment A
OPUC Safety Report
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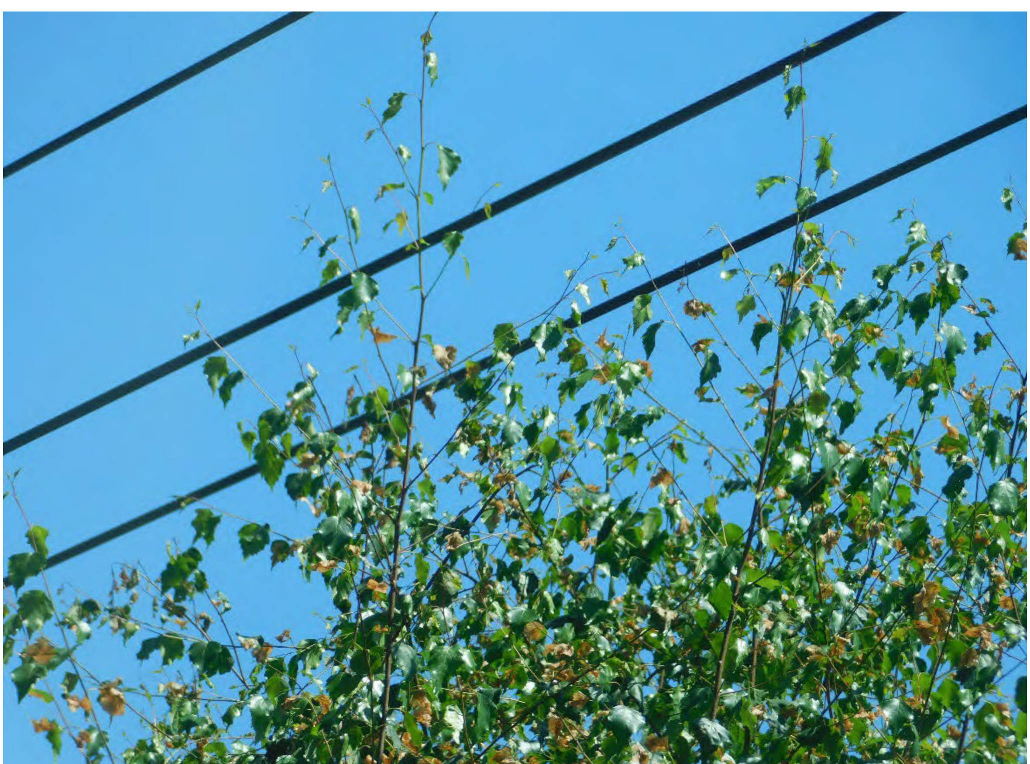
Probable violation B.298:
Tree shows evidence
of contacting primary
conductors at
599 South Settlemier
Avenue, Woodburn.
(45.1386, -122.8640)

Probable violation B.299:
Two trees show evidence
of contacting primary
conductors at
583 West Hayes Street,
Woodburn.
(45.1451 -122.8596)

Attachment A
OPUC Safety Report
E22-62R 5

Probable violation B.300:
Tree shows evidence
of contacting primary
conductors at
3635 5th Street, Hubbard.
(45.1839, -122.8087)



Probable violation B.301:
Tree shows evidence
of contacting primary
conductors at
19598 Pacific Highway
East, Aurora.
(45.2028, -122.7791)

Probable violation B.302:
Tree shows evidence
of contacting primary
conductors at
20337 Pacific Highway
East, Aurora.
(45.2133, -122.7700)

Probable violation B.303:
Tree shows evidence
of contacting primary
conductors at
25393 Pacific Highway
East, Aurora.
(45.2392, -122.7370)

Attachment A
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Probable violation B.304:
Tree shows evidence of contacting primary conductors at 531 Doud Street, Woodburn.
(45.1427, -122.8535)

Probable violation B.305:
Two trees show evidence of contacting primary conductors at 765 South Pacific Highway, Woodburn.
(45.1290, -122.8526)

Attachment A
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Probable violation B.306:
Tree shows evidence of contacting primary conductors at 1050 South Pacific Highway, Woodburn. (45.1235, -122.8557)

Probable violation B.307:
Two trees show evidence of contacting primary conductors at 6098 Topaz Street NE, Salem. (45.0620, -122.9364)

Attachment A
OPUC Safety Report
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Probable violation B.308:
Multiple trees show evidence of contacting primary conductors at 6198 Topaz Street NE, Salem.
(45.0597 -122.9340)

Probable violation B.309:
Tree shows evidence of contacting primary conductors at 4375 Turner Road South, Salem.
(44.8901, -122.9854)

Attachment A
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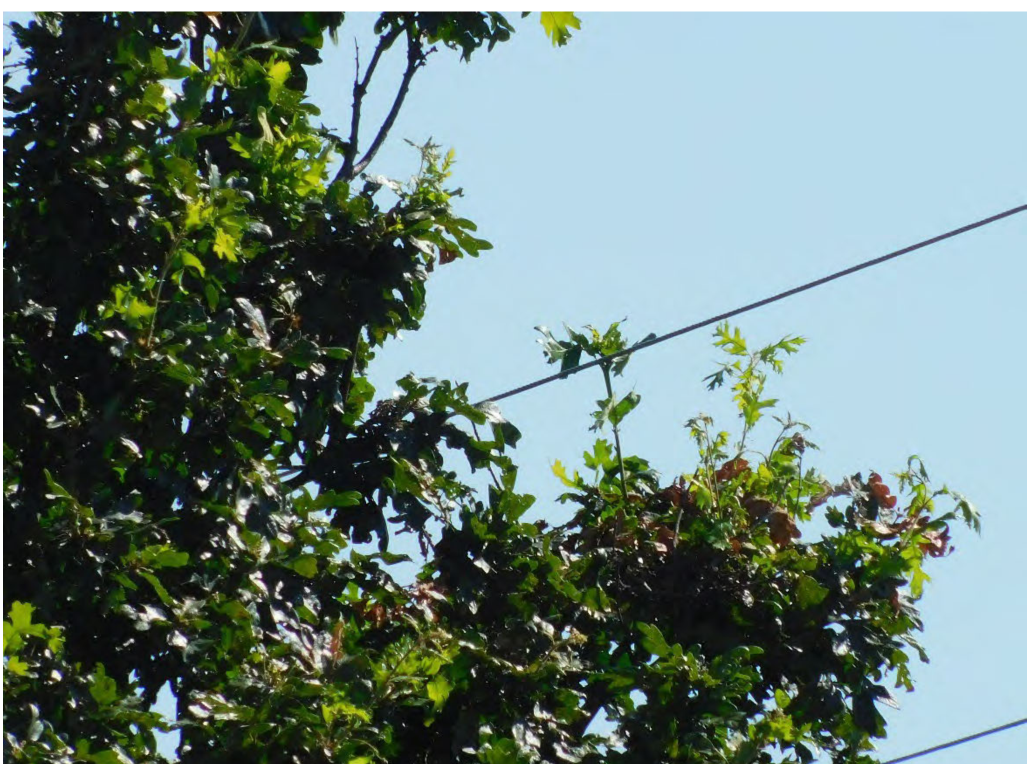
Probable violation B.310:
Tree shows evidence
of contacting primary
conductors at
14985 Woodburn/Monitor
Road NE, Woodburn.
(45.1021, -122.7528)

Probable violation B.311:
Tree shows evidence
of contacting primary
conductors at
14779 South Vaughan
Road, Molalla.
(45.1596, -122.5639)

Attachment A
OPUC Safety Report
E22-62R 5

Probable violation B.312:
Tree shows evidence of contacting primary conductors at 30330 South Molalla Avenue, Molalla. (45.1678, -122.5757)



Probable violation B.313:
Multiple trees show evidence of contacting primary conductors at 30286 South Molalla Avenue, Molalla. (45.1690, -122.5753)

Attachment A
OPUC Safety Report
E22-62R 5

Probable violation B.314: Tree shows evidence of contacting primary conductors at 14551 South Macksburg Road, Molalla. (45.1797, -122.5637)

Probable violation B.315: Multiple trees show evidence of contacting primary conductors on South Macksburg Road, Molalla. (45.1765, -122.5582)

Probable violation B.316:
Tree shows evidence
of contacting primary
conductors at
15143 South Macksburg
Road, Molalla.
(45.1660, -122.5473)

Probable violation B.317:
Tree shows evidence
of contacting primary
conductors at
17355 South Hallbacka
Lane, Mulino.
(45.1732, -122.5111)

Probable violation B.318: Tree shows evidence of contacting primary conductors on South Monroe Lane, Mulino (45.1740 -122.5163)

Probable violation B.319: Tree shows evidence of contacting primary conductors across from 25949 South Hillockburn Road, Estacada. (45.2303, -122.3247)
HFRZ

Attachment A
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Probable violation B.320: Tree shows evidence of contacting primary conductors across from 28383 South Baurer Road, Colton.
(45.1949, -122.4144)

Probable violation B.321: Tree shows evidence of contacting primary conductors on Woodburn/Estacada Highway, Colton.
(45.1700, -122.4598)

Probable violation B.322:
Tree shows evidence
of contacting primary
conductors at
29444 South Salo Road,
Mulino.
(45.1799, -122.5229)

Probable violation B.323:
Tree shows evidence
of contacting primary
conductors across from
28631 South Salo Road,
Mulino.
(45.1934, -122.5278)

Attachment A
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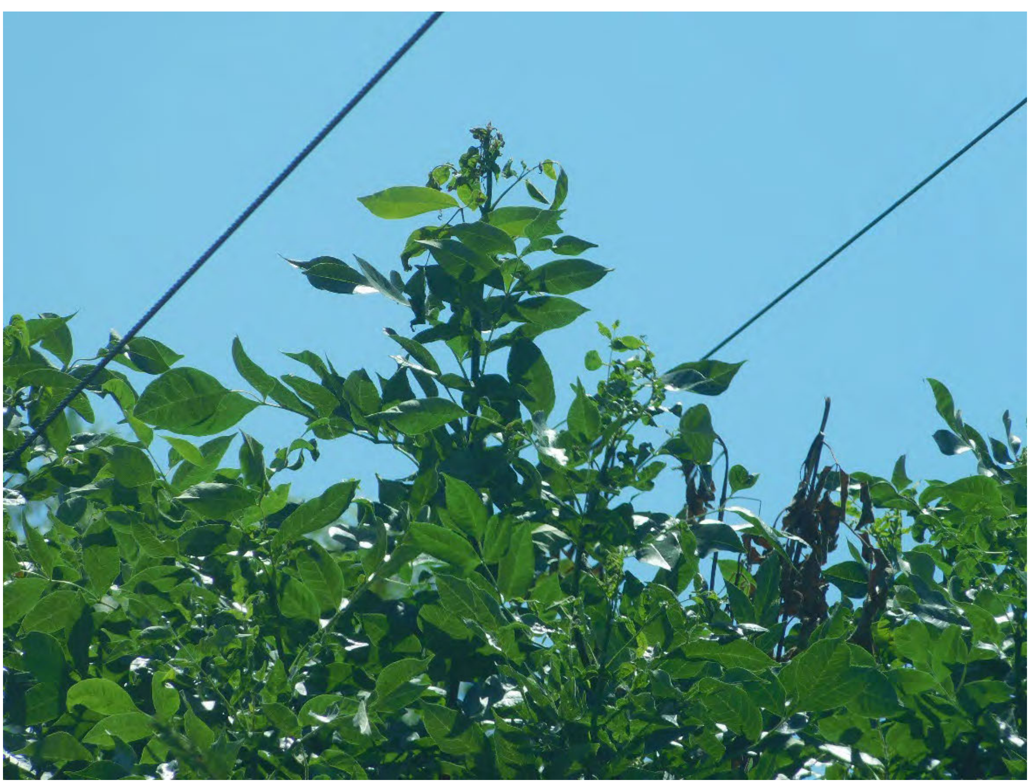
Probable violation B.324:
Tree shows evidence
of contacting primary
conductors at
15704 South Windy City
Road, Mulino.
(45.1941, -122.5416)



Probable violation B.325:
Tree shows evidence
of contacting primary
conductors at
28605 South Marshal
Road, Mulino.
(45.1934 -122.5435)

Probable violation B.326:
Tree shows evidence of contacting primary conductors at 29264 South Marshal Road, Mulino.
(45.1829, -122.5426)

Probable violation B.327:
Tree shows evidence of contacting primary conductors on SW Newland Road, Wilsonville.
(45.3507, -122.7227)

Probable violation B.328:
Tree shows evidence
of contacting primary
conductors at
23939 SW Gage Road,
Wilsonville.
(45.3472, -122.7305)

Probable violation B.329: Multiple trees show evidence of contacting primary conductors at 23300 South Blount Road, Canby.
(45.2693, -122.6557)

Probable violation B.330: Tree shows evidence of contacting primary conductors at the intersection of South Bremer Road and South Haines Road, Canby.
(45.2711, -122.6613)

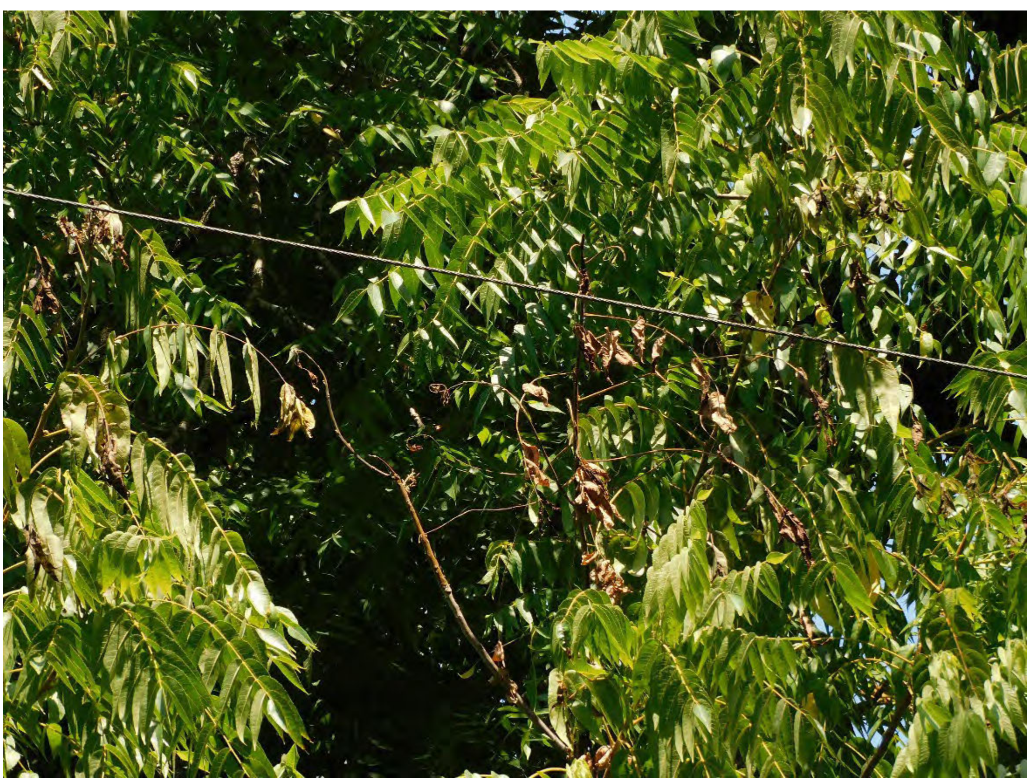
Probable violation B.331:
Tree shows evidence
of contacting primary
conductors at
10730 South Beutel Road,
Oregon City.
(45.3272, -122.6482)

Probable violation B.332:
Tree shows evidence
of contacting primary
conductors at
507 3rd Street, Oregon
City.
(45.3537, -122.6087)

Probable violation B.333: Tree shows evidence of contacting primary conductors at 15275 South Maplelane Road, Oregon City. (45.3382, -122.553)

Probable violation B.334: Tree shows evidence of contacting primary conductors at 15199 South Maplelane Road, Oregon City. (45.3378, -122.5545)

Probable violation B.335:
Two trees show evidence of contacting primary conductors on South Maplelane Road, Oregon City.
(45.3371, -122.5619)

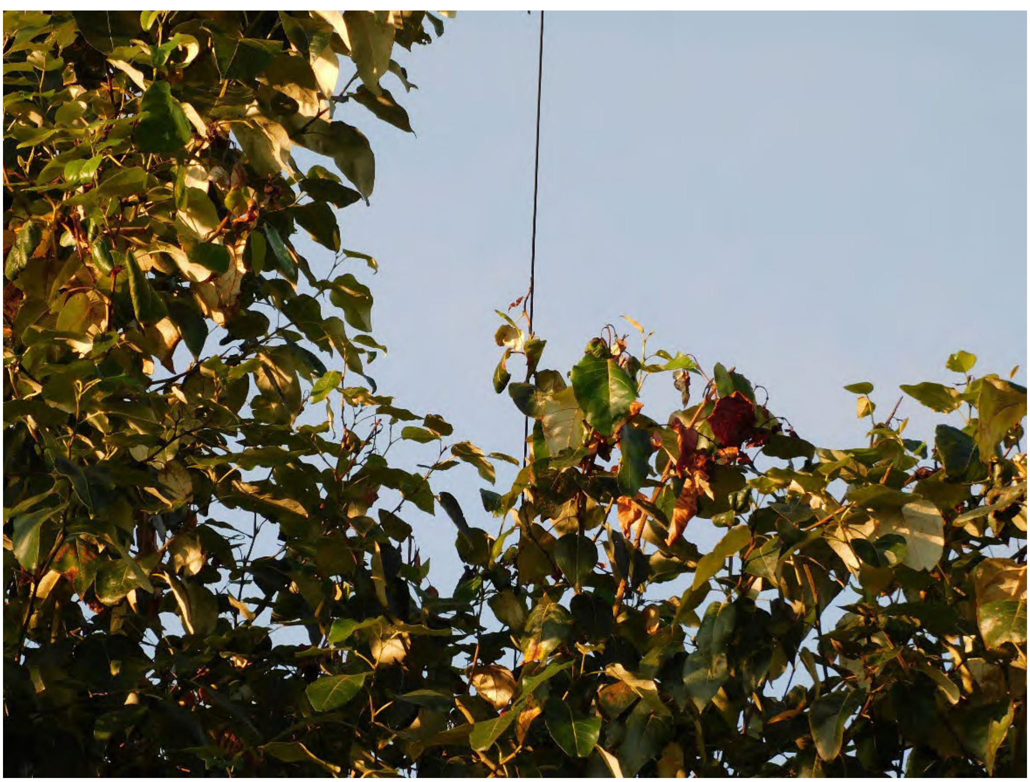


Probable violation B.336:
Two trees show evidence of contacting primary conductors at 15107 Thayer Road, Oregon City.
(45.3312, -122.5569)

Probable violation B.337:
Tree shows evidence
of contacting primary
conductors on
South Lower Highland
Road, Beaver Creek.
(45.2621, -122.5014)

Probable violation B.338:
Tree shows evidence
of contacting primary
conductors at
15618 South Carus Road,
Oregon City.
(45.2714, -122.5469)

Probable violation B.339:
Tree shows evidence of contacting primary conductors at 16747 South Hattan Road, Oregon City.
(45.3628, -122.4916)



Probable violation B.340:
Tree shows evidence of contacting primary conductors at 15908 South Springwater Road, Oregon City.
(45.3753, -122.4744)

Probable violation B.341:
Two trees show evidence of contacting primary conductors on South Springwater Road, Oregon City.
(45.3700, -122.4716)

Probable violation B.342:
Tree shows evidence of contacting primary conductors at 16268 South Babler Road, Oregon City.
(45.3710, -122.4539)

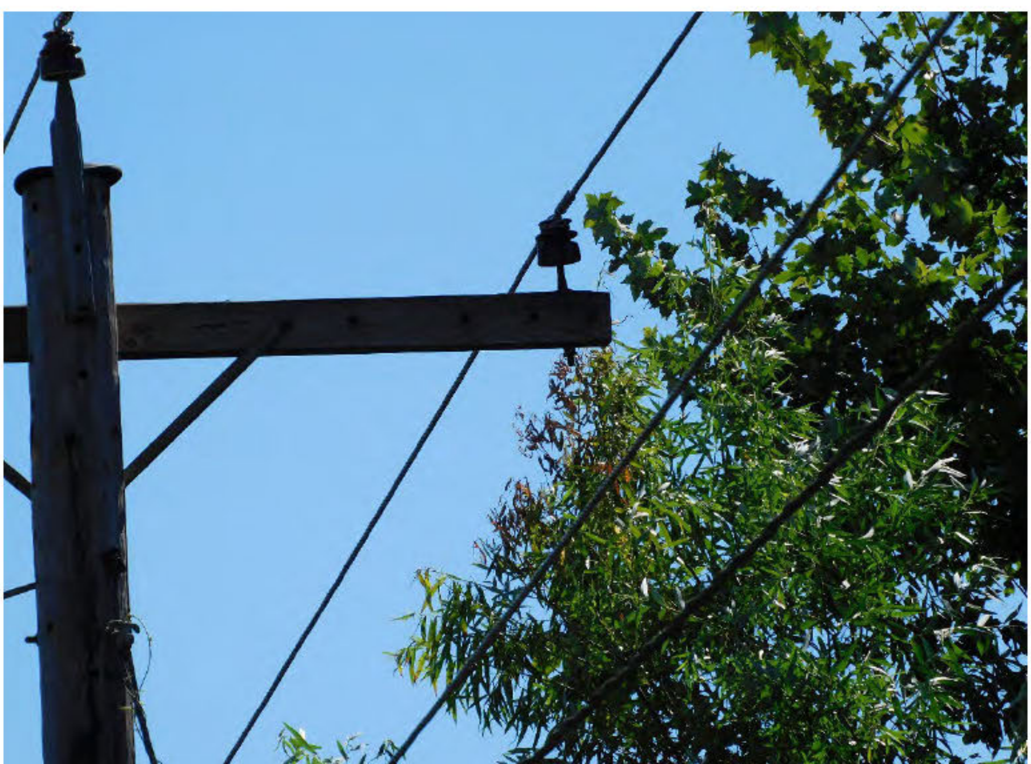
Probable violation B.343:
Two trees show evidence of contacting primary conductors on South Gerber Road, Oregon City.
(45.3737, -122.4433)

Probable violation B.344:
Multiple trees show evidence of contacting primary conductors at 13300 SE Hubbard Road, Clackamas.
(45.4140, -122.5274)

Probable violation B.345:
Tree shows evidence
of contacting primary
conductors at
13780 SE Bluff, Sandy.
(45.4238, -122.2742)

Probable violation B.346:
Two trees show evidence
of contacting primary
conductors on
SE Hudson Road, Boring.
(45.4435, -122.2744)

Probable violation B.347:
Tree shows evidence
of contacting primary
conductors on
SE Littlepage Road,
Corbett.
(45.5083, -122.2857)



Probable violation B.348:
Tree shows evidence
of contacting primary
conductors on
US-30 Historic, Troutdale.
(45.5189, -122.3367)

Attachment A
OPUC Safety Report
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Probable violation B.349:
Tree shows evidence
of contacting primary
conductors at
3514 SE 317th Avenue,
Troutdale.
(45.4976, -122.3367)

Probable violation B.350:
Two trees show evidence
of contacting primary
conductors at
3768 SE 317th Avenue,
Troutdale.
(45.4956, -122.3367)

Probable violation B.351:
Tree shows evidence of contacting primary conductors on SE Victory Road, Troutdale.
(45.4938, -122.3364)

Probable violation B.352:
Multiple trees show evidence of contacting primary conductors on SE Lusted Road, Gresham.
(45.4759, -122.3323)

Attachment A
OPUC Safety Report
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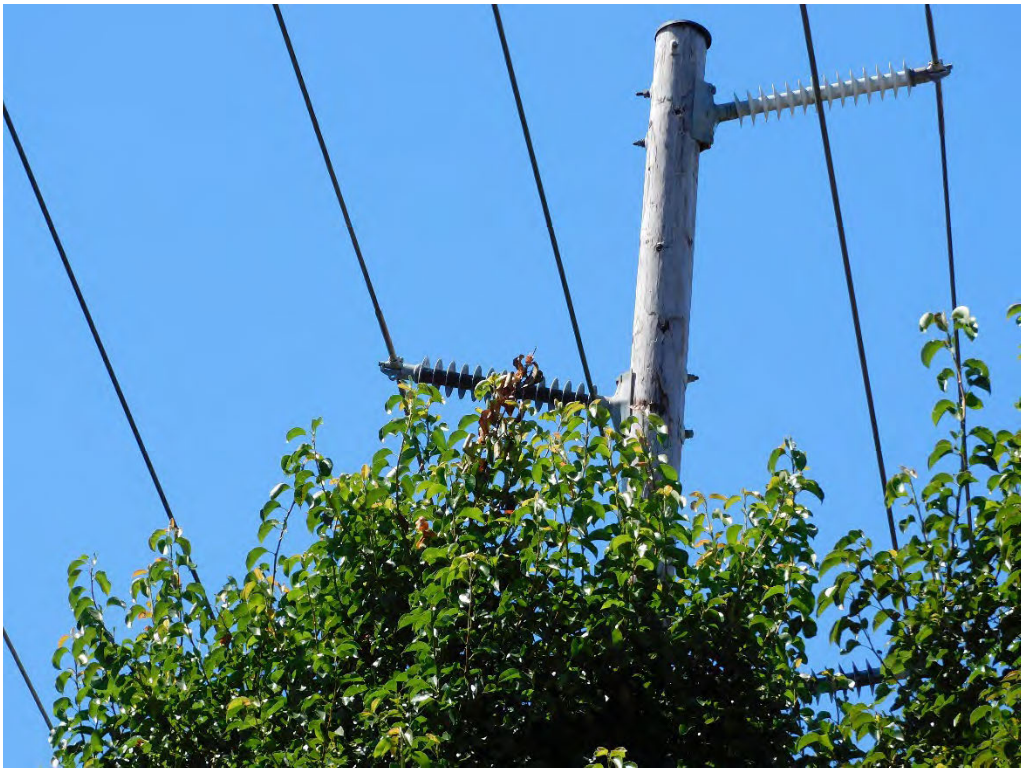

Probable violation B.353:
Tree shows evidence of contacting primary conductors on SE Dodge Park Blvd., Gresham.
(45.4705, -122.3475)

Probable violation B.354:
Multiple trees show evidence of contacting primary conductors at the intersection of SE Dodge Park Blvd. and SE 302nd Avenue, Gresham.
(45.4708, -122.3528)

Probable violation B.355:
Tree shows evidence of contacting primary conductors on SE Jackson Road, Gresham.
(45.4739, -122.3493)

Probable violation B.356:
Multiple trees show evidence of contacting primary conductors at 30945 SE Jackson Road, Gresham.
(45.4739, -122.3451)

Probable violation B.357: Multiple trees show evidence of contacting primary conductors at 30830 SE Bluff, Gresham. (45.4652, -122.3451)

Probable violation B.358: Tree shows evidence of contacting primary conductors at 34727 SE Compton Road, Boring. (45.4327, -122.3059)

Probable violation B.359:
Tree shows evidence
of contacting primary
conductors at
33755 SE Compton Road,
Boring.
(45.4327, -122.3154)

Probable violation B.360:
Tree shows evidence
of contacting primary
conductors at
33685 SE Compton Road,
Boring.
(45.4327, -122.3164)

Probable violation B.361: Multiple trees show evidence of contacting primary conductors at 33685 SE Compton Road, Boring.
(45.4327, -122.3272)

Probable violation B.362: Multiple trees show evidence of contacting primary conductors at 11422 SE Revenue Road, Boring.
(45.4411, -122.3315)

Probable violation B.363:
Two trees show evidence of contacting primary conductors at
10905 SE Revenue Road, Boring.
(45.4438, -122.3322)

Probable violation B.364:
Tree shows evidence of contacting primary conductors at
8444 SE Orient Drive, Gresham.
(45.462, -122.3486)

Probable violation B.365:
Tree shows evidence
of contacting primary
conductors across from
8801 SE 307th Avenue,
Boring.
(45.4591, -122.3471)

Probable violation B.366:
Tree shows evidence
of contacting primary
conductors at
1265 SE Roberts Avenue,
Gresham.
(45.4872, -122.4203)

Probable violation B.367: Multiple trees show evidence of contacting primary conductors on NE Glisan Street, Portland.
(45.5263, -122.5283)

Probable violation B.368: Tree shows evidence of contacting primary conductors at 12155 SE Harold Street, Portland.
(45.4833, -122.5383)

Probable violation B.369:
Multiple trees show evidence of contacting primary conductors at 6625 SE 182nd Avenue, Gresham.
(45.4745, -122.4757)

Probable violation B.370:
Multiple trees show evidence of contacting primary conductors at 11528 SE Tyler Road, Happy Valley.
(45.4504, -122.5438)

Probable violation B.371:
Two trees show evidence of contacting primary conductors at
9615 SE Eastview Drive, Happy Valley.
(45.4536, -122.5482)

Probable violation B.372:
Multiple trees show evidence of contacting primary conductors on
SE Ridgeway Drive, Happy Valley.
(45.4539, -122.5505)

Attachment A
OPUC Safety Report
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Probable violation B.373:
Tree shows evidence of contacting primary conductors on SE 129TH Avenue, Happy Valley.
(45.4380, -122.5358)

Probable violation B.374:
Tree shows evidence of contacting primary conductors on SE King Road, Happy Valley.
(45.4470, -122.5247)

Probable violation B.375:
Tree shows evidence of contacting primary conductors on SE Richey Road, Gresham.
(45.4654, -122.4812)

Probable violation B.376:
Two trees show evidence of contacting primary conductors at 17745 SE Richey Road, Gresham.
(45.4656, -122.4793)

Probable violation B.377: Tree shows evidence of contacting primary conductors on SE Regner Road, Gresham. (45.4782, -122.4292)

Probable violation B.378: Multiple trees show evidence of contacting primary conductors on SE Clatsop Street, Happy Valley. (45.4614, -122.5195)

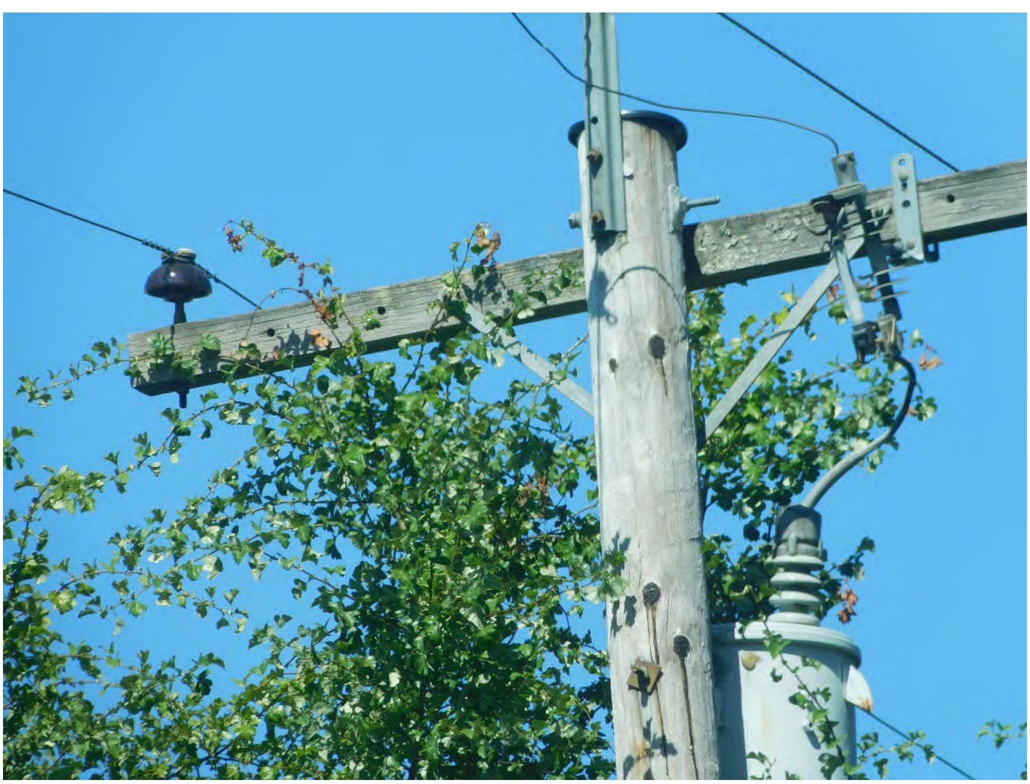
Probable violation B.379:
Tree shows evidence of contacting primary conductors at 8690 SE 140th Place, Happy Valley.
(45.4600, -122.5197)

Probable violation B.380:
Tree shows evidence of contacting primary conductors at 13463 SE Kanne Road, Happy Valley.
(45.4573, -122.5246)

Probable violation C.1: Vines engulfing pole are creating a **climbing hazard** at 1537 South Dogwood Street, Cornelius. (45.5166, -123.0526)

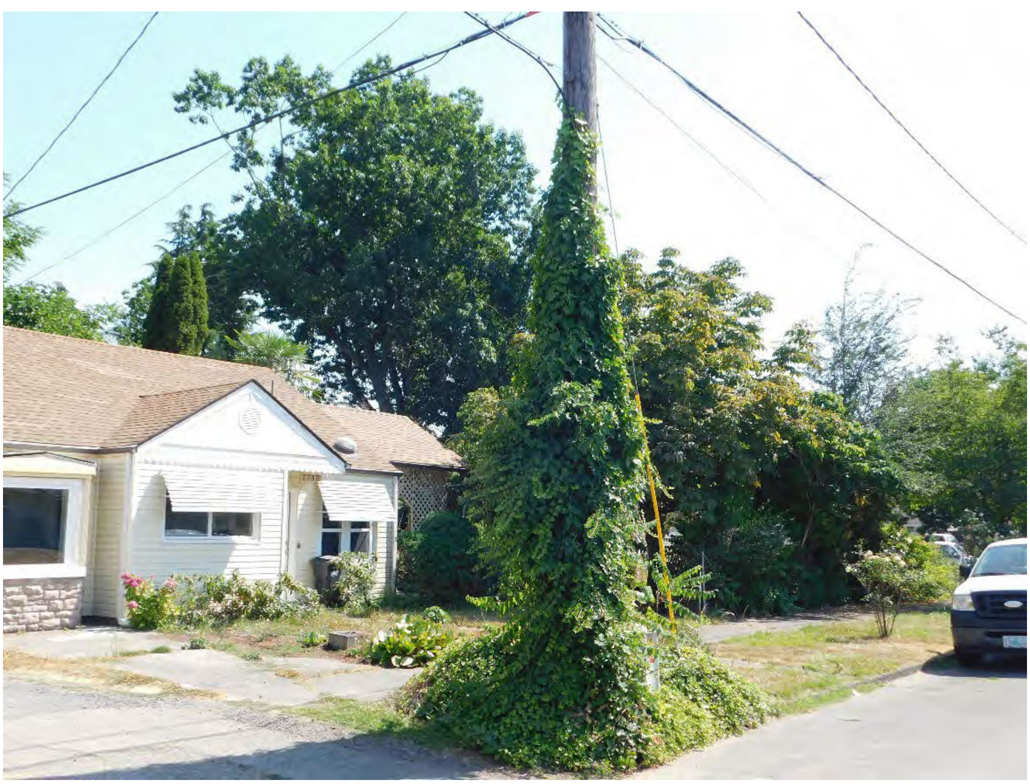
Probable violation C.2: Vines engulfing pole and approaching primary conductor are **creating a hazard** at 12473 Ferry Road NE, Aurora. (45.2132, -122.8056)

Probable violation C.3:
Vines engulfing pole
are creating a **climbing hazard** at
2796 Glen Haven Road,
Lake Oswego.
(45.4031, -122.7064)



Probable violation C.4:
Vines engulfing pole and
approaching primary
conductor are **creating a hazard** at
17731 SE River Road,
Portland.
(45.3945, -122.6236)

Probable violation C.5: Vines engulfing pole and approaching primary conductor are **creating a hazard** at the intersection of SE Aldercrest Court and SE Thiessen Road, Portland. (45.4162, -122.5992)



Probable violation C.6: Vines engulfing pole are creating a **climbing hazard** at
1740 Baker Street NE, Salem.
(44.9529, -123.0174)

Attachment A
OPUC Safety Report
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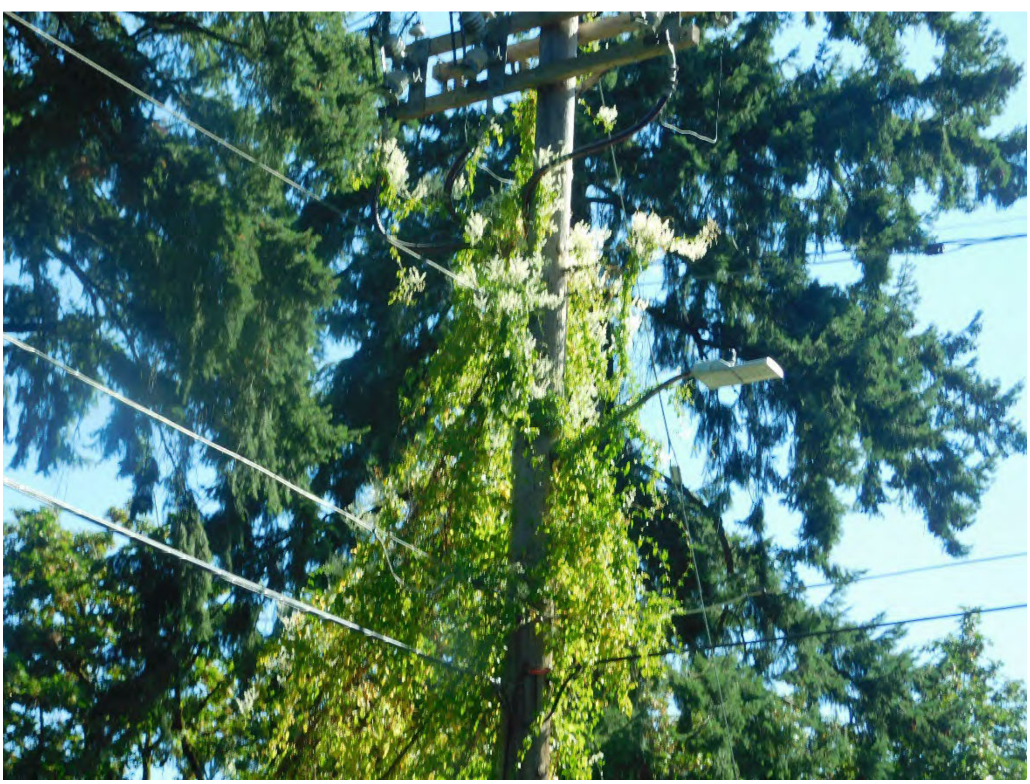
Probable violation C.7:
Vines engulfing pole are creating a **climbing hazard** on Lockhaven Drive North, Keizer.
(45.0044, -123.0278)

Probable violation C.8:
Vines engulfing pole and approaching primary conductor are **creating a hazard** at 1356 Meadowlark Drive, Keizer.
(45.0122, -123.0149)

Probable violation C.9:
Vines engulfing pole and approaching primary conductor are **creating a hazard** at 2710 SE Rutland Terrace, Portland.
(45.5209, -122.7082)



Probable violation C.10:
Vines engulfing two poles are creating a **climbing hazard** across from 114 SW Kingston Avenue, Portland.
(45.5237, -122.7063)

Probable violation C.11: Vines engulfing pole and approaching primary conductor are **creating a hazard** on SW Prosperity Park Road, Tualatin. (45.3712, -122.7300)

Probable violation C.12: Vines engulfing pole are creating a **climbing hazard** on SW Mountain Road, West Linn. (45.3536, -122.7098)

Probable violation C.13:
Vines engulfing pole are creating a **climbing hazard** on
SW Schaeffer Road, West Linn.
(45.3527, -122.7088)

Probable violation C.14:
Vines engulfing pole are creating a **climbing hazard** on
SW Golpher Valley Road, Sheridan.
(45.1694, -123.3783)

Probable violation C.15: Vines engulfing pole are creating a **climbing hazard** at 311 Ganong Street, Oregon City. (45.3462, -122.6194)

Probable violation C.16: Vines engulfing pole are creating a **climbing hazard** at 14831 South Maplelane Road, Oregon City. (45.3371, -122.5614)

Attachment A
OPUC Safety Report
E22-67R 7

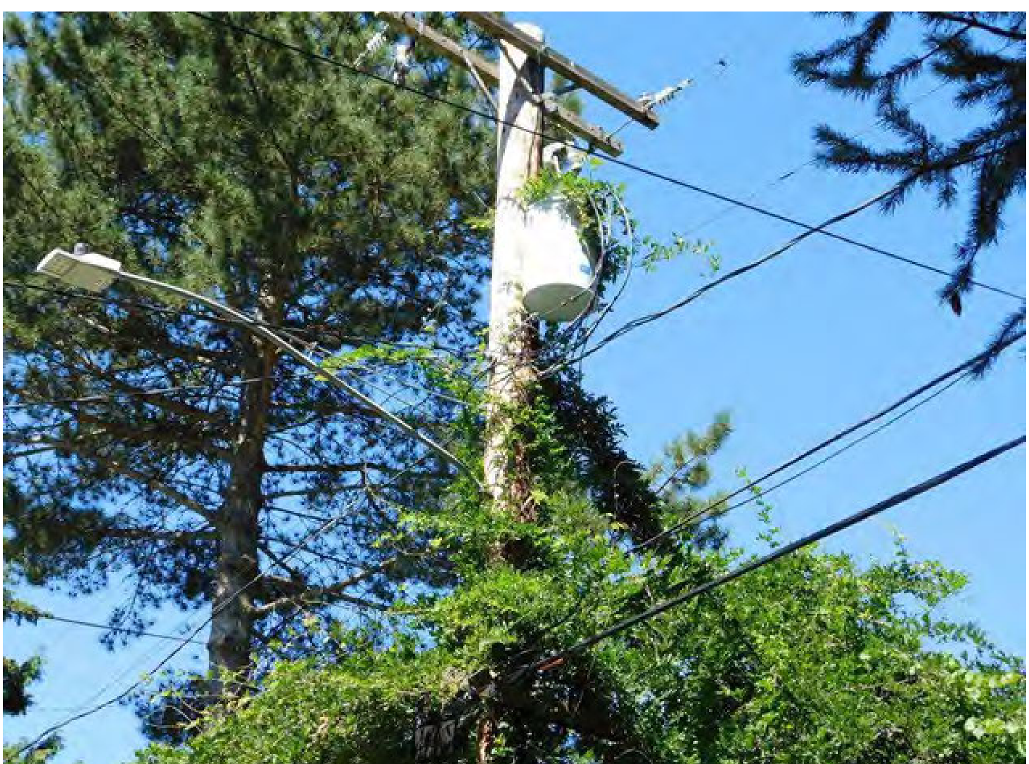
Probable violation C.17: Vines engulfing pole and approaching primary conductor are creating a **hazard** at
247 SE 4th Street,
Troutdale.
(45.5387, -122.3864)

Probable violation C.18: Vines engulfing pole are creating a **climbing hazard** at
921 SW Davenport Street, Portland.
(45.5054, -122.6879)

Probable violation C.19: Vines engulfing pole are creating a **climbing hazard** at
840 SW Canning Street, Portland.
(45.5046, -122.6879)

Probable violation C.20: Vines engulfing pole are creating a **climbing hazard** at
5166 SW 26th Drive, Portland.
(45.4854, -122.7066)

Probable violation C.21: Vines engulfing pole are creating a **climbing hazard** at 6510 SW 32nd Avenue, Portland. (45.4775, -122.7095)



Probable violation C.22: Vines engulfing pole and approaching primary conductor are **creating a hazard** at 3539 SW Nevada Court, Portland. (45.4726, -122.7134)

Attachment A
OPUC Safety Report
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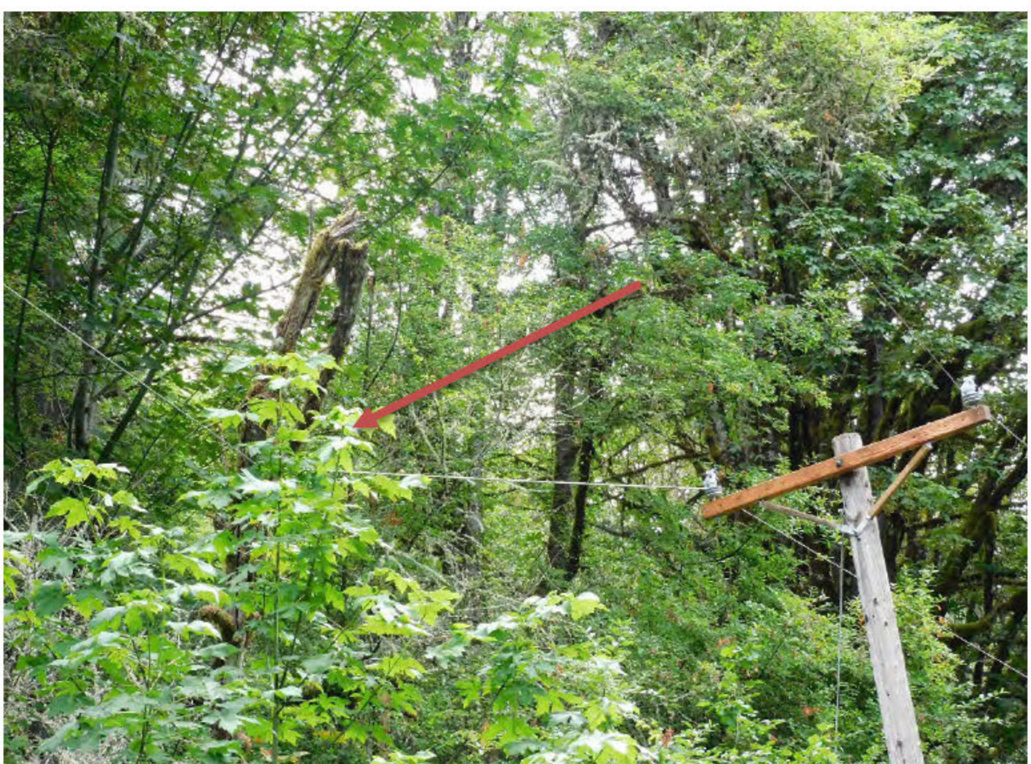
Probable violation C.23: Vines engulfing pole are creating a **climbing hazard** at the intersection of South Blount Road and South Bremer Road, Canby. (45.2711, -122.6557)



Probable violation D.1: Conductor energized below 600 volts is under strain or abrasion from vegetation on NW Davidson Road, Banks. (45.6326, -123.0755)

Probable violation D.2: Conductor energized below 600 volts is under strain or abrasion from vegetation across from 16389 South Hagen Road, Happy Valley. (45.4394, -122.4951)

CASE: UE 416
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3400

Rebuttal Testimony
Grid Modernization and
Proposed Schedule 122 Update

August 22, 2023

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

A. My name is Curtis Dlouhy. I am an economist and senior utility analyst employed in the Utility Strategy and Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Are you the same Curtis Dlouhy that sponsored Staff testimony previously in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of this testimony is to address stakeholders' opening testimonies and the Company's Reply Testimony on how to interpret the term "associated energy storage" in ORS 469A.120 for the purposes of the renewable resource automatic adjustment clause in Schedule 122.

ISSUE 1. PROPOSED SCHEDULE 122 UPDATE

Q. Please briefly summarize the Company's proposal regarding the renewable resource automatic adjustment clause (RAC) in Schedule 122?[1]

A. In its Opening Testimony, the Company requests that the Commission clarify that the "associated energy storage" language included in ORS 469A.120, the statute addressing cost recovery of costs incurred to meet the State's Renewable Portfolio Standard (RPS), means that standalone storage qualifies for cost recovery through the RAC.[2] The Company states that it believes that on-system standalone storage provides integrating and firming services for renewable energy sources and thus should qualify for the RAC. In making their case for the inclusion of standalone batteries in the RAC, the Company cites the Inflation Reduction Act (IRA) allowing more Investment Tax Credits (ITCs) for batteries and the language in HB 2021 that require the utility to demonstrate continual development of supporting infrastructure to meet decarbonization goals.[3]

Q. How did Staff reply to this in its Opening Testimony in this docket?

A. Staff recommended that the Commission not allow standalone storage to qualify for inclusion in the RAC at this time. In making this recommendation, Staff made it clear that this was not a blanket recommendation to not include

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1 It should be noted that the Company abbreviates the Renewable Resource Automatic Adjustment Clause as RAAC in their Reply Testimony but RAC in their opening testimony. Staff will continue to refer to it as the RAC.
2 PGE/1300, Macfarlane – Pleasant/46.
3 PGE/1300, Macfarlane – Pleasant/47.

standalone storage in the subset of renewable resources, but rather to maintain the status quo of allowing only generating resources or co-located generating and storage resources into the RAC until the Commission could reevaluate the role of the RAC in a post-HB 2021 landscape with a more complete group of utilities and stakeholders.[4]

Staff made this recommendation recognizing that there are some key opposing forces regarding cost recovery through the RAC. First, the definition of "associated energy storage" is something left to the Commission's discretion for interpretation, and to date, Staff is unaware of any RAC proceedings where standalone batteries have been considered. Second, as discussed in Staff Exhibit 2200 and 1100, Staff believes that the Company relies too heavily on automatic adjustment clauses (AACs), which unfairly skews the balance of risk in ratemaking from shareholders to customers. Third, the RAC was clearly designed in a pre-HB 2021 world where its purpose was to aid in renewable portfolio standards (RPS) compliance, but it is very apparent that any future use of the RAC would be used for HB 2021 compliance.[5]

Q. How did parties react to the Company's proposal in this proceeding?

A. The Citizens' Utility Board (CUB) was the only other party to write testimony on this issue and opposed PGE's proposal to treat standalone storage as "associated energy storage". CUB asserts that the correct interpretation of the language is that "associated energy storage" is energy storage that is co-

[4] Staff/1100, Dlouhy/22.
[5] Staff/1100, Dlouhy/15.

located with an RPS-eligible resource.[6] CUB notes that the Company's proposed definition is sufficiently broad to allow *any* standalone storage resources to qualify for the RAC.[7] CUB goes on to state that allowing such a permissive definition could then be used to interpret the "associated transmission" language contained in the ORS 469A.120 to make all new transmission projects eligible for cost recovery through the RAC in a post-HB 2021 landscape.[8]

Q. How did the Company respond to the arguments brought up by CUB and Staff in its Reply Testimony?

A. The Company believes that CUB's interpretation of "associated energy storage" is impractically narrow and ignores the reliability benefits to renewables of having storage on the system.[9] The Company also takes issue with CUB's stance that the Company's definition could be taken to mean that any storage or transmission project would qualify for the RAC.[10]

The Company also notes that its current renewable generation and bank of Renewable Energy Credits (RECs) will be insufficient to meet its RPS obligations in 2034, therefore standalone batteries put in the RAC today will help firm and integrate renewable resources used for RPS obligations in the future.[11] The Company then urges the Commission to adopt more limited

6 CUB/200, Jenks/52.
7 CUB/200, Jenks/53.
8 CUB/200, Jenks/54.
9 PGE/2700, Blosser – Sheeran/5.
10 PGE/2700, Blosser – Sheeran/8.
11 PGE/2700, Blosser – Sheeran/14.

language defining "associated energy storage" than the Company introduced in this round of testimony rather than discussing the best use of the RAC in a future proceeding.[12]

Q. What new language does the Company propose to define "associated energy storage"?

A. The Company proposes that "associated energy storage" be defined as "all co-located energy storage and standalone storage connected at the transmission-voltage level that are used to integrate, firm or shape renewable energy sources."[13]

Q. How does Staff respond to the Company's general arguments in its Reply Testimony and its updates to its proposed definition of "associated energy storage"?

A. Staff appreciates PGE's update to its definition of "associated energy storage" that in effect narrows the scope of qualifying standalone storage projects to those that are "near" renewable resources rather than strictly co-located with renewable resources. However, this update does not adequately address two of Staff's main concerns from opening testimony:

1. The RAC was created with RPS in mind, but the Company is using it to recover costs associated with storage that clearly has no RPS value for at least the next decade.

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12 PGE/2700, Blosser – Sheeran/17.
13 PGE/2700, Blosser – Sheeran/4.

> Any decision regarding treatment of standalone storage should be made in a more generic proceeding with other utilities and stakeholders rather than a utility-specific rate case.

With these two unaddressed concerns in mind, Staff continues to recommend that the Commission exclude standalone energy storage from the RAC for at least the time being. Staff also continues to recommend that the Commission determine at a later proceeding whether standalone storage should qualify and how to properly adapt the RAC to fit into a post-HB 2021 landscape, if at all.

Q. Do you have any concerns with the Company's proposed language updates?

A. Yes, although I will again point out that my current concerns are just related to implementing the language *at this time*. Staff questions whether the language proposed by the Company places any effective limits on the standalone storage resources the Company plans to pursue. Given that this language would likely shape future cost recovery, I struggle to see the value in more precise language that imposes nonbinding constraints. I would like to reiterate that I recommend having a more complete discussion of the proposed language as well as other proposed futures for the RAC at a future proceeding.

Q. The Company disagrees with CUB's argument that allowing any standalone batteries to qualify for the RAC is akin to saying that Western EIM, demand response programs, or Port Westward II should qualify for the RAC. How do you respond?

A. I believe that the Company is sidestepping the broader point in its flat dismissal of CUB's point. The Company states that investments described by CUB do not count because these are not storage resources. However, it appears that the point CUB makes is that if the goal is to allow anything that integrates renewables into the RAC as associated storage, then one would expect that other investments that integrate renewables would qualify for inclusion in the RAC as well. While Staff believes it to be the case that the intent of the language is to apply to physical plant that helps firm and integrate renewables, Staff agrees with CUB's example and overall point that the language of "associated energy storage" is meant to convey that not every storage project or physical plant necessarily qualifies for the RAC.

Q. Do you believe that the Company's updated language serves as a reasonable way to define what does and does not count as "associated energy storage"?

A. Perhaps, but I still believe that the relative benefits of this language and other proposals should be weighed against each other with a wide array of stakeholders, most notably PacifiCorp which would also presumably be using the RAC for procurement in service of its HB 2021 obligations.

Q. If you think that the updated language may perhaps be reasonable, why do you oppose using the proposed language in the interim?

A. Staff believes that even making a non-precedential change on policy issues has the potential to limit the conversation in a future proceeding. While it may indeed be true that a future proceeding ends with a version of the Company's proposed language, Staff worries that stakeholders involved in this rate case would enter into a future proceeding with the mindset that the proposed language is the starting point, which may improperly skew conversations. Given the long-reaching implications of possibly using the RAC to recover costs in next two decades as utilities procure almost exclusively renewable resources to comply with HB 2021, I believe that there is time to start with a broad scope and ensure that a holistic update to the RAC makes sense. As previously expressed, I also questions whether the language proposed by the Company places any effective limits on the standalone storage resources the Company plans to pursue.

Q. Your first concern above is that the RAC was meant to work alongside RPS. Why do you believe that the Company should not be allowed to use the RAC for the two standalone storage projects discussed in its testimony?

A. As was stated in Staff's opening testimony, Staff believes that the RAC's role should be re-evaluated in a post-HB 2021 world given that it was both created and last modified years before HB 2021 was put into law. When proposed, the RAC was clearly signed into law aid in RPS procurement, but RPS compliance is not driving either of the storage projects that the Company discusses in its Reply Testimony or any part of its IRP for that matter.

Q. How do you know that the two battery projects are being procured to firm or shape renewables for RPS compliance?

A. In its Reply Testimony, the Company states that it does not expect to have an RPS need that is not met by current resources until 2034.[14] While I understand that there is value in acquiring resources with some lead time, I cannot agree that a ten-year lead time is reasonable if the storage is being procured for RPS reasons.

Q. Why would the RAC need to be re-evaluated even if the Company has RPS needs in the future?

A. As I described in Opening Testimony and confirmed by the Company in its Reply Testimony,[15] RPS obligations are not driving incremental resource additions. Put another way, if RPS laws were to disappear – and with them, the RAC which was made with RPS in mind – the Company's resource strategy would not change. Therefore, Staff finds no compelling reason to recommend including storage resources in the RAC that only questionably fit the definition of "associated energy storage."

Staff again feels the need to reiterate that Staff recommends the Commission undertake an investigation into how HB 2021 may affect implementation of the RPS and ORS 469A.120. However, at the moment, Staff still feels it most appropriate to clarify that standalone storage resources are not eligible for the RAC until a future proceeding where the RAC can be addressed more holistically.

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[14] PGE/2700, Blosser – Sheeran/14.
[15] PGE/2700, Blosser – Sheeran/14.

Q. Regarding your second point, are there any reasons you believe that the use of the RAC should be determined at a future proceeding that you have not already discussed in past rounds of testimony?

A. Yes. In other proceedings and informal conversations with stakeholders, Staff has been made aware of concerns regarding how the RAC treats issues of depreciation. While Staff working on this rate case is not fully apprised of this issue, I believe that a future proceeding devoted to integrating the RAC into a post-HB 2021 landscape could help provide clarity on this issue and any other issues that arise. As previously stated, I view it to be incredibly important to fully flesh out the RAC's role in HB 2021 given its scale and ambition rather than make incremental changes.

Q. Please restate your overall recommendation regarding the RAC.

A. I recommend that the Commission clarify that "associated energy storage" does not apply to standalone storage for the time being. I further recommend that the Commission determine at a future proceeding how to properly use the RAC in a post HB-2021 landscape.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: Bret Farrell

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3500

REPLY TESTIMONY
Uncollectible Expense

August 22, 2023

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

A. My name is Bret Farrell. I am a Senior Utility and Energy Analyst employed in the Utility Strategy and Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1201.

Q. What is the purpose of your testimony?

A. I am responding to the Company's Reply Testimony regarding Uncollectible Expense.

ISSUE 1. UNCOLLECTIBLE EXPENSE

Q. Please summarize the Company's initial proposal for uncollectible expense.

A. In opening testimony, PGE proposed a forward-looking uncollectible rate methodology in which the Company estimates the test year uncollectible rate by taking the approved uncollectible rate in UE 335 (0.3262 percent) and adding seven distinct adjustments. The adjustments put forth by the Company cover the following issues:

- Economic Conditions
- Covid Bill Assistance Expiring
- Deposit Adder
- Division 21: Weather Disconnect Protections
- Division 21: 15-day notice to 20-day notice
- Collection Agency Recovery Rate
- Income-Qualified Bill Discount (IQBD) Program

The result of this methodology is a forecasted uncollectible rate of 0.5272 percent which the Company reduced to 0.5 percent to "mitigate the customer price increase in this GRC".

Q. Please describe Staff's analysis and recommendations in Opening Testimony.

A. Staff reviewed the Company's forward-looking methodology and adjustment calculations and found that the methodology put forth by the Company is not sufficiently robust to justify deviating from the historic precedent of a three-year average. Staff argued that each of the Company's adjustment either lacked sufficient data/evidence, used a calculation with improper assumptions, or attempted to estimate the impact of a policy prematurely.

Q. How did the Company respond to Staff's proposed treatment of Uncollectible expense?

A. In Reply Testimony, the Company disagreed with Staff's overall approach of a three-year average methodology and attempted to refute each of the objections raised by Staff for the individual adjustments put forth by the Company in their forward-looking methodology.

Q. Please describe the Company's objections to Staff's three-year average methodology.

A. The Company claims:

1. The three-year average is not a Commission precedent and each instance where it has been adopted by the Commission has been the result of a stipulation between parties.
2. Methodologies applying more or fewer than three years have been used in previous dockets to account for anomalous circumstances.
3. When the use of a three-year average fails to consider changes in fundamental conditions it will not reasonably reflect the expected forward-looking conditions.
4. The 2020-2022 period is an unreliable predictor of the test year uncollectible rate because of the impact of the COVID-19 pandemic and the Company's COVID-19 deferral.

Q. Has the Company used a three-year average methodology in previous dockets?

A. Yes. PGE used a three-year average methodology for the uncollectible rate most recently in Docket No. UE 335, Docket No. UE 319, and Docket No. UE 294. In Docket No. UE 319 the Company initially proposed the use of a five-year average stating that "A five-year average better reflects economic cycles and normalizes significant one-time positive or negative events".[1]

Q. How does Staff respond to the Company's claims about the three-year average methodology not being a Commission precedent?

A. The Company claims that the use of a three-year average is not a "Commission" precedent, which is true in the sense that that the Commission has not adopted a policy prescribing this methodology for calculating the uncollectible rate when utilities file a GRC. However, the use of either a three-year average methodology or some other form of a rolling-average methodology has been common practice for setting test year uncollectible rate across multiple utilities GRCs over the past several years.[2] The Company itself advocated for the use of a rolling-average methodology in Docket UE

1 See PGE/900 Stathis–Dillin/6.

2 *See, e.g., In the Matter of Avista Corporation*, UG 246, Order No. 14-015 at 3 (January 21, 2014) and *In the* Matter *of Avista Corporation*, Docket UG 186, Order No. 09-422, Appendix A at 4 (October 26, 2009) (adopting stipulations for Avista general rate increase with uncollectible expense in revenue requirement based on three-year average); *but see In the Matter of Idaho Power Company*, UE 167, Order No. 05-871 (January 28, 2005) (adopting stipulation for Idaho Power Company general rate increase with uncollectible expense based on four-year average) and *In the Matter of Cascade Natural Gas Corporation*, UG 287, Order No. 15-412 (December 28, 2015) (adopting stipulation for Cascade Natural Gas general rate increase with uncollectible expense based on three-year average, removing an anomalous year).

319.[3] Staff believes that given the consistent use of this approach in previous dockets and the historic agreement on this approach among parties, that a deviation from this approach must be sufficiently justified. Staff believes that the Company fails to justify their forward-looking approach.

Q. Why does Staff believe the Company has failed to justify their forward-looking methodology?

A. Staff believes the Company has failed to justify its forward-looking methodology for several reasons. In particular:

1. Estimating the impact of individual factors on the uncollectible rate requires making assumptions about the relationship between these factors and the uncollectible rate. For several of the adjustments put forth by the Company, the assumptions about the relationship between certain factors and the uncollectible rate are purely speculative because there is no historic evidence or data to examine to substantiate these relationships. Conversely, a three-year average approach requires no complex assumptions and relies solely on historical data.
2. Estimating the impact of multiple variables on a single variable such as the uncollectible rate, typically involves complex statistical modelling, a significant source of underlying data, and multiple robustness checks. At the very least it requires performing a simple regression. The Company does none of these things. The calculations the Company makes to arrive at its adjustments are rudimentary, lacking sufficient data, and

[3] See PGE/900 Stathis–Dillin/6.

broadly speculative. Conversely, the three-year average methodology requires no complex modeling, while still identifying and tracking the overall trend of the uncollectible rate and smoothing out year-over-year variations.

3. The Company's forward-looking approach assumes that the only factors impacting the uncollectible rate in the test year are the seven factors chosen by the Company. So, in addition to failing to establish a substantiated connection between the Company's chosen factors and the uncollectible rate, the Company's approach ignores the broad spectrum of variables that could be impacting the test year uncollectible rate, including the recent trends in the uncollectible rate. In situations where there are potentially dozens of factors that could be impacting a forecasted variable, but not single dominant factor can be identified, attempting to estimate individual impacts is extremely challenging. Using a rolling-average in these situations provides a practical alternative that considers the overall historical trend without delving into the complexities of factor analysis.

4. The relationship between variables can often change and shift over time. If the Company's methodology were to be adopted moving forward, a new forecast of all factors influencing the test year uncollectible rate would need to be produced for each subsequent GRC. Identifying all potential factors that could influence the test year uncollectible rate, examining the relationship between new potential factors and the uncollectible rate, and

reexamining the relationship between existing factors and the uncollectible rate to determine whether they had changed, would prove extremely difficult. Adopting this methodology moving forward would likely produce increasingly imprecise forecasts in future GRCs.

Ultimately, Staff believes that the Company's approach of examining individual factors and then attempting to estimate the impact of each of them on the test year uncollectible rate is inherently flawed, likely imprecise, and hubristic.

Q. Why does Staff believe that a three-year average approach is superior?

A. A rolling-average methodology, such as the three-year average approach is meant to track the overall trend of the uncollectible rate while smoothing out year-over-year variances. By taking a rolling-average, underlying changes to the uncollectible rate are gradually incorporated into the test year forecast. This ensures that key variables influencing the uncollectible rate are being factored into the test-year forecast and that the effect of anomalous events are limited. The rolling-average also requires no complex modeling, no tenuous assumptions, and is practically simple and straight-forward.

Furthermore, rolling averages can be particularly useful in identifying turning points or inflection periods. When a trend starts to change direction, the rolling-average tends to respond more gradually, providing a more reliable signal of a potential shift in the forecasted variable. Staff therefore believes that this methodology better accounts for fundamental changes and will therefore more reasonably reflect forward-looking conditions, contrary to the Company's claims.

Q. How does Staff respond to the Company's claim that the 2020-2022 period is an unreliable predictor of the test year uncollectible rate because of the impact of the COVID-19 pandemic?

A. Staff believes that the purpose of the three-year average methodology is to smooth out year-over-year variances and anomalous events such as the COVID-19 pandemic. The uncollectible rates observed by the Company during the period from 2020-2022 were not extreme outliers in comparison to historic uncollectible rates, therefore Staff believes that the period is an adequate predictor of the test year uncollectible rate.

Q. How did the Company respond to Staff's analysis of each of the individual adjustments put forth by the Company?

A. The Company rehashes initial arguments from their opening testimony about why each individual adjustment is necessary and warranted. PGE attempts to refute Staff's claims about insufficient data and poor assumptions in the calculations of the adjustments.

Q. How does Staff respond to the Company's claims about each of the individual adjustments?

A. Staff reiterates the arguments made in opening testimony that the methodology put forth by the Company is not sufficiently robust to justify deviating from the three-year average approach. Staff believes that each of the Company's adjustments lacks sufficient data/evidence, uses a calculation with improper assumptions, or attempts to estimate the impact of a policy prematurely.

Q. What is Staff's proposed adjustment for the uncollectible rate and uncollectible expense for the 2024 test year?

A. Staff, again, proposes using the three-year average of the uncollectible rate between 2020-2022. PGE provided this average, an uncollectible rate of 0.33 percent in response to Staff Data Request 595. Staff proposes applying this rate to the final agreed-upon general revenues to calculate the appropriate level of uncollectible expense to be included in the 2024 test year. At this time, based on the Company's proposed general revenues in Exhibit 201, Staff proposes a decrease to the Company's test year uncollectible expense of $5,289,000.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3600

Rebuttal Testimony

August 22, 2023

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

A. My name is Julie Jent. I am a Senior Economist in the Energy Costs Section of the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is found in Exhibit No. Staff/1300 and my witness qualifications statement is provided in Exhibit No. Staff/101.

Q. What is the purpose of your testimony?

A. The purpose of this rebuttal testimony is to address the Company's testimony on the qualifying facilities (QF) pass-through for the Company's Automatic Update Tariff (AUT) and Staff's rate base adjustment for capitalized wages and salaries, FTEs, and incentives.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit 3601, which contains Staff's updated Wages and Salaries Model.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. WAGES AND SALARIES[1]

Q. Have Staff and other parties reached a stipulated agreement regarding Staff's proposed adjustments to Test Year expense for compensation, i.e., wages and salaries and incentives?

A. Yes. Staff and other parties reached a stipulated agreement that resolves Staff's proposed adjustments to PGE's Test Year expense for wages and salary, FTEs, incentives, and some related expense items. However, PGE's Test Year Revenue Requirement includes capitalized wages and salaries and incentives that have not been addressed by stipulation.

Staff's original wages and salaries/incentive adjustment proposed in Opening Testimony was comprised of a capital adjustment (40.9 percent) and an O&M expense (59.1 percent) adjustment. My testimony below is focused on the Staff proposed capital adjustment for (1) wages and salaries, (2) FTE, and (3) incentives.

Q. Please restate Staff's method for adjusting wages and salaries in its Opening Testimony.

A. The Wage and Salary model began with 2021 actuals for wages and overtime and adjusts them by a year-over-year escalation of expenses using the All-Urban CPI to establish a forecast for the Test Year. In effect, the model calculates the average salary based on the Company's actual Base Year

[1] This is discussed in Exhibit 1800 of PGE's Reply Testimony, from pages 105-134 of their pdf. This is discussed again in Exhibit 2200 on transmission and distribution as Staff's removal of FTE was duplicative.

calendar payroll (2021), divided by the actual Base Year FTE (2021), and then escalates the average by the annual changes to the All-Urban CPI.

Once the escalated amount is determined, it is compared to the Company's Test Year figures. At this point the sharing principle is applied, wherein Staff adjusts its forecasted amount to allow the Company to share 50/50 the lesser of the difference between the model forecast and the amount the Company has included in its Test Year or a 10 percent band around Staff's projection. The two projections are compared, and the model chooses the lower of the Test Years.

Q. Does Staff have an updated recommendation on the capital portion of the wages and salaries adjustment?

A. Yes. Staff recommends using the updated CPI values for 2023 and 2024 that were published by the Office of Economic Analysis in July. Using these more accurate values, Staff recommends reducing the capital portion of wages and salaries by $459,000.

Q. Why does the Company object to this?

A. PGE takes issue with the fact that the model chooses the lesser of the two options. PGE argues that Staff's model *will actually* produce a total forecasted wage and salary increase of $19.6 million greater than PGE's projections.[2] PGE refers to a "calculation design that replaces any positive

[2] See Exhibit 1801, Wages and Salaries Workpaper to see PGE's unconstrained model.

variance with a zero-dollar amount".[3] The Company responded by submitting an "unconstrained" version of Staff's model.

Q. Further detail how the Company's unconstrained calculations differ from that of Staff's projections.

A. The main difference in the total recommended adjustment hinges on the union salaries both in straight time labor and over-time. When looking at just the rate base portion, PGE's model recommends only a $29,000 adjustment. In addition, PGE used incorrect allocation percentages in the model they submitted. Instead of using 59.1 percent and 40.9 percent, they have two different percentages in their model for each of the parts of the adjustment. I see in their model 50.1 and 63.3 percent used for O&M and 40.9 and 36.7 percent for rate base.

Q. What is Staff's response to the treatment of Union salaries?

A. As stated above, the model chooses the lower of the Test Year projection created by the model or Company's Test Year request. PGE is essentially saying that because union salaries were projected to be higher, but their request came in at a lower value, that we should instead accept the larger value. We could even separate out the wages from union salaries in our model as the increases are determined not by the CPI but are based on bargaining agreements. By choosing to go with their model, it completely changes how the model is meant to work and is intended to work.

[3] PGE/1800, Mersereau -Neitzke, page 4-5.

Q. Is Staff's application of the Wages and Salary model new in this docket?

A. No. The Staff Wage and Salary model has always operated as it is in this docket. It is intended to be a check on escalation which opts for the lesser cost projection. If one examines the formulas present, they are the same as those submitted in PGE's last general rate case (UE 394): IF formulas that state if Staff's projection is less than the Company's, a zero will be substituted.

Q. What could be the cause for the model projecting higher costs than the Company?

A. The Wage and Salary model escalates compensation by the All-Urban CPI. U.S. inflation reached a record high of 9.1 percent in June 2022, the highest level since 1982.[4] The Wage and Salary model used inflation rates of **8.0**, **4.5,** and **2.75** percent for 2022-2024. For contrast, in PGE's last general rate case (UG 394),[5] the Wage and Salary model escalated using CPI rates of 1.2, 3.7 and 2.4 percent for 2020-2022 sourced from the September 2021 Oregon Economic and Revenue forecast.[6]

Q. Does Staff have an updated recommendation to the capital side of PGE's FTE?

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4 U.S. inflation at 9.1 percent, a record high | PBS NewsHour

5 See UG 394 Staff/304, Staff electronic workpaper, Exhibit 304 W&S CONF.xlsx, tab 3-year W&S.

6 Oregon Economic & Revenue Forecast September 2021, Volume XLI, No. 3, Table A.4, page 37.

A. Yes, because PGE's 2024 test year forecast included costs for approximately 190 more FTE than its most recent year of actuals (2022) and 160 more FTE than its 2019 actuals and updated CPI numbers needed to be used. Staff proposed an adjustment based on PGE's most recent head count (March 30, 2023) in Staff Opening Testimony.[7] A reduction to the Company's head count amounted to a decrease of 91 FTE ($3.5 million of which is the rate base adjustment), mostly pronounced in the Exempt and Non-Exempt categories.[8] Staff did not make adjustments to the number of union employees. The adjustment is in alignment with Order 01-787 which states that employee levels should be based on actual levels at a specified date.

Q. What was the Company's reaction to Staff's recommended FTE reduction?

A. PGE stated that Staff's use of head count or FTE to right-size the Company's labor requirements was inaccurate since it is based on straight time labor and does not reflect the different types of labor PGE utilizes to meet the needs of the business. In its filing, PGE stated it would like to focus on total labor dollars instead of FTE as more consistent with the approach the Company's management takes when viewing resources.[9] PGE made a similar argument for the Commission in docket UE 197 when

[7] Staff/1300.
[8] See Staff electronic work paper in Exhibit 1303 W&S CONF.xlsx. See also Staff electronic workpaper, Exhibit 3601 Rebuttal UE 416 Exhibit 3601 Wage and Salary Model.xlxs. The first workpaper was submitted as confidential but because the model has now been a part of the public record in other dockets, because PGE's unconstrained model was submitted as non-confidential, and because the model uses non-confidential DRs, Staff has decided to submit its workpaper as non-confidential.
[9] PGE/300, Mersereau – Neitzke/14.

the Company's filing increased FTE by 130 positions, citing "the need for FTE levels to be based on known and measurable changes in the resources needed to meet PGE's regulatory and compliance requirements." However, the Commission rejected PGE's "proposed incremental approach to calculating test-year FTE" and adopted Staff's approach to applying the historical growth rate in FTE.[10]

In addition, PGE makes several arguments stating that the use of straight time FTE does not accurately reflect PGE's total labor requirements. However, when examining PGE's total labor dollars (including temps and contract labor), the biggest ticket item is still straight time labor which increased from 64% of total labor dollars in 2019 to 76% in 2022.[11]

FIGURE 1: TOTAL LABOR DOLLARS, DR 251 ATTACH A

Row Labels	2019 Budget	2020 Budget	2021 Budget	2022 Budget	2019 % of total cost	2020 % of Total Cost	2021 % of total Cost	2022 % of total cost
1101 - Straight-Time Labor - Salary	$160,608,637	$171,928,581	$179,178,202	$215,491,099	45.02%	50.35%	52.28%	54.09%
1102 - Straight-Time Labor - Union	$64,845,187	$61,156,054	$65,015,982	$66,882,523	18.17%	17.91%	18.97%	16.79%
1103 - Straight-Time Labor - Hourly	$22,901,544	$23,044,623	$20,657,953	$21,503,994	6.42%	6.75%	6.03%	5.40%
1200 - Other Union Labor	$1,588,154	$2,427,331	$2,721,208	$3,849,218	0.45%	0.71%	0.79%	0.97%
1202 - Union Premium Pay	$0	$277,591			0.00%	0.08%	0.00%	0.00%
1401 - Overtime - Hourly	$1,123,244	$1,233,409	$1,295,554	$1,393,350	0.31%	0.36%	0.38%	0.35%
1402 - Overtime - Union	$18,204,591	$14,306,913	$14,870,066	$19,476,146	5.10%	4.19%	4.34%	4.89%
1501 - Temporary Labor Straight Time	$8,742,335	$3,471,558	$2,922,127	$1,592,130	2.45%	1.02%	0.85%	0.40%
1502 - Non-PGE Labor Straight Time	$39,576,143	$24,398,344	$12,094,577	$17,947,099	11.09%	7.15%	3.53%	4.50%
1601 - Temporary Labor Overtime	$174,156	$30,584	$28,792	$74,107	0.05%	0.01%	0.01%	0.02%
1602 - Non-PGE Labor Overtime	$475,942	$917,486	$2,004,200	$5,287,919	0.13%	0.27%	0.58%	1.33%
5104 - Vacation Overhead	$45,636,714	$43,970,157	$47,343,325	$51,911,668	12.79%	12.88%	13.81%	13.03%
5501 - Labor Allocation - ST Salary	$125,686	-$11,212	-$134,143	-$14,456	0.04%	0.00%	-0.04%	0.00%
5502 - Labor Allocation-ST Hrly Union	$125,877	-$82	-$1,954	-$110	0.04%	0.00%	0.00%	0.00%
5503 - Labor Allocation-ST Hrly NonUn	$32,457	-$962	-$5,404	-$1,149	0.01%	0.00%	0.00%	0.00%
5505 - Labor Allocation-Union Premium	$0	$0	$0	$0	0.00%	0.00%	0.00%	0.00%
5506 - Labor Allocation - Hourly OT	$8	-$7	-$15	-$9	0.00%	0.00%	0.00%	0.00%
5507 - Labor Allocation-Union HrlyOT	$0	$0	$0	$0	0.00%	0.00%	0.00%	0.00%
5509 - Labor Allocation-ST Temporary	-$1,049,465	-$110	-$283	-$143	-0.29%	0.00%	0.00%	0.00%
7001 - Joint Owner Credit	-$6,327,010	-$5,702,448	-$5,283,368	-$6,965,056	-1.77%	-1.67%	-1.54%	-1.75%
Grand Total	$356,784,201	$341,447,812	$342,706,819	$398,428,329				

[10] *In the Matter of* Portland *General Electric Company*, Docket UE 197, Order 09-020 at 7 (1/22/09).

[11] Staff/1301, PGE's Response to Staff DR No. 251 Attach A (Excel worksheet).

PGE claims straight time labor doesn't represent its labor needs, yet it is the largest labor expense and the fastest growing.

Q. Why does Staff believe that the requested amount of FTE in this GRC should be adjusted downward?

A. Staff reasserts a concern it has had with FTE since Docket No. UE 319, in which "PGE proposed growing its FTE by 270 FTE from 2016 to its 2018 test year."[12] Moreover, PGE has historically budgeted more FTEs than is necessary as can be shown from an examination of its Budgeted and Actual FTE where PGE overestimated its 2020, 2021, and 2022 budgets by 292, 276, and 121 FTE, respectively.[13]

FIGURE 2: FTE BUDGET AND ACTUALS 2018-2019

2018		*2019*		*2020*		*2021*		*2022*		*2023*	*2024*
Forecast	Actual	Forecast	Actual	Budget	Actuals	Budget	Actuals	Forecast	Actuals	Budget	Budget
2851	2872	2868	2924	3067	2775	2995	2719	2939	2818	3036	3006
	-21		-56		**292**		**276**		**121**		**30**

PGE's 2023 FTE budget of 3,036, on the other hand, is the highest it has ever been, evinced by data from the last three rate cases going back to 2018.[14] While 2022 actuals represent a 3.6 percent increase from 2021 actuals, the 2023 budget bears little resemblance to the 2022 actuals and increases by 218 FTE in one year.

Q. How much greater is their 2024 forecast than their 2022 actuals?

12 UE 319 Staff/400, Gardner/37 at 15-19 and /38 at 1-23.

13 See Staff/1301, PGE Response to Staff DR 250 Attachment A (electronic spreadsheet) and DR 418 Attachment A (electronic spreadsheet).

14 See Staff/1301, PGE Response to Staff DR 250 Attachment A (electronic spreadsheet) and DR 418 Attachment A (electronic spreadsheet).

A. PGE's pro rata adjustment decreases its FTE count by 97. However, Staff argues that a reduction on a bloated budget is not a real reduction. Even with the adjustment, PGE has added 190 FTE (or 7%) from its 2022 actuals.[15]

Staff's use of the head count is a higher revenue requirement alternative than choosing a three-year average. Had Staff used a three-year average of available actuals (2020-2022 average=2,751 for all employees and 2,109 for non-union), a recommendation for a 217 FTE reduction would have been made (again making no adjustment to union FTE). Given the discrepancies between PGE's historical projections and actuals, Staff thought it prudent to use a measure of up-to-date actuals (March 2023) such as head count.

Q. Does Staff have any further comments on PGE's claims?

A. Yes. PGE is incorrect in saying that Staff based most of the wages and salaries adjustment on 2022 actuals. Staff starts with actuals in 2021 and escalates them up either by the bargaining increases or the CPI.

In addition, PGE states that a high correlation should mean that FTE numbers are not relevant, and that labor should just be looked at by total labor values. Staff disagrees. A high correlation does not mean the two figures should not be viewed in isolation. PGE did not address the fact that

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[15] Please note the value of 2,818 above in taken from a separate DR whereas the value 2,816 which is used in this calculation is taken from response to SDR 92.

even when those positions go unfilled, this would be money recovered in rates but going to other operational areas.

Q. Does Staff have an update to their rate base side of the Incentive adjustment?

A. Yes. The bulk of Staff's adjustment is to non-officer incentives as Staff intended to right-size the amount in the Test Year by comparing it with a three-year average. The three-year average, excluding officers, (approximately $29 million) was $10.8 million below what was originally in the test year for non-officer incentives ($40.7 million).

Staff also wants to highlight the difference between the Company's 2022 actuals ($31 million) and 2023 Budget ($38 million) in the area of non-officer incentives as well. The likes of $38 million in non-officer incentives has not been apparent in the three years of historical actuals yet PGE sees fit to use this inflated number in its budget. Staff argues that half of an inflated number is still inflated.[16]

Therefore, Staff recommends a downward $2.2 million rate base adjustment to incentives.

Q. Summarize Staff's updated recommendations to the rate base side of wages and salaries, FTE, and incentives.

A. Staff recommends a permanent rate base adjustment to Wages and salaries of ($458,856). Staff recommends a permanent rate base adjustment to FTE of ($3,518,704). Staff Recommends a permanent rate base adjustment to

[16] See Staff Exhibit 300, Staff Opening Testimony.

incentives of ($2,208,099). This is a total recommended permanent reduction to rate base of $6,185,659. Staff recommends the Commission direct PGE to include this adjustment to rate base in future general rate filings and to depreciate the rate base adjustment consistent with the asset lives for which the labor was contributing to.

ISSUE 2. QF PASS-THROUGH

Q. Restate Staff's position from Opening Testimony regarding PGE's proposed pass through of QF costs in the annual AUTs.

A. Staff recommended that the Commission approve PGE's recommendation of a QF pass-through in the AUT, which would work as follows:

- PGE would forecast QF costs for the following NVPC test year based on the rolling average of the most recent full years of QF generation, up to three historical years.
- PGE would file a deferral application to defer for later recovery or to refund the variance between forecasted and actual QF costs.
- After the conclusion of the forecasted year, PGE's actual QF costs would be compared to forecasted costs.
- The resulting surplus or deficit would be passed through to customers the following AUT proceeding as either a charge or a refund to customers based on the difference between the contract price collected from customers in the NVPC forecast and the day-ahead Mid-C power price. In addition, this variance would capture any delay damages the QF pays for failing to meet the contractual online date.
- The price for the Mid-C would include a weighting of the light load and heavy load hours by the respective hours in the day.

Q. How did PGE Reply?

A. PGE did not write Reply Testimony addressing the QF pass-through as this was a settled issue initially, but PGE and Staff have differences in calculation methods for the pass-through. Staff and PGE had discussions on the calculation to be performed for the pass-through on July 26 and August 3. As we could not come to an agreement on the method, Staff has informed PGE that we would be writing rebuttal testimony on the topic.

Q. What is Staff's updated recommendation?

A. Staff still supports a QF pass-through but disagrees with PGE on the mechanics. The following is how Staff would calculate the adjustment for the QF forecast in mWh. For the equation below, let "p" stand for supplier, "f" stand for forecast, "A" stand for actual, "C" stand for cost or price of the QF project, and j for hours (1 to 8760 hours).

$(QFf_{pj} - QFA_{aj}) * (Mid\ CA_{aj} - QF_{pcj})$

- In this equation, if the QF output forecast matches actual output there is no adjustment.
- If the QF for supplier p for hourly price c as in the QF power purchase contract for hour j is the same as the Mid C actual price in hour j there is no adjustment.
- For example, if the forecast mWh output is greater than actual and the QF price is greater than Mid C then the adjustment to power cost is negative (credit to customers).

Q. Why does Staff support this method of calculating the QF pass-through?

A. Staff believes the purpose of a pass-through is to protect against changes to QF's output and not to protect against wholesale price risk.

Q. Did other intervenors comment on this issue?

A. No, not in their Opening Testimony.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESSES: Curtis Dlouhy, Matt Muldoon,
Michelle Scala, and Bret Stevens

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3700

REBUTTAL TESTIMONY
Automatic Adjustment Clauses (AAC)
Role in Regulation, and
Need for Deferrals with AACs

August 22, 2023

Q. Please introduce yourselves.

A. I, Dr. Curtis Dlouhy introduce myself in Exhibit Staff/300 and provide my witness qualifications in Exhibit Staff/301.

I, Matt Muldoon introduce myself in Exhibit Staff/400 and provide my witness qualifications in Exhibit Staff/401.

I, Michelle Scala introduce myself in Exhibit Staff/600 and provide my witness qualifications in Exhibit Staff/601.

I, Dr. Bret Stevens introduce myself in Exhibit Staff/2000 and provide my witness qualifications in Exhibit Staff/2001.

Q. What is the purpose of this testimony?

A. This testimony responds to Portland General Electric Company's (PGE or Company) Reply Testimony contained in PGE Exhibit 2900 on Automatic Adjustment Clauses (AAC) and the need for deferrals with AACs. This testimony is also informed by the Opening Testimony of Intervenors.

Q. Did you prepare any exhibits for this docket?

A. Yes. We prepared the following exhibits:

- Exhibit Staff/2201, Responses to Data Requests used in Support of Testimony.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations in its Opening Testimony, identifying any adjustments Staff proposes.

A. Staff made the following recommendations in its Opening Testimony:[1]

1. Consolidate AAC Schedules:

   Staff recommended that the existing schedules associated with AACs be consolidated into fewer schedules where the tariffs recover costs from the same customer groups. Staff has identified the following schedules as eligible for consolidation under this proposal: 137 (Customer-owned solar payment option cost recovery mechanism (CRM), 136 (Oregon Community Solar Program Start-up CRM), 150 (Transportation Cost Recovery), and 153 (Community Benefits and Impacts Advisory Group CRM) as a single tariff, and separately, schedules 135 (Demand Response CRM) and 138 (Energy Storage CRM) as a single tariff. This consolidation would bring greater efficiency and readability to stakeholders and streamline the ratemaking process.

2. Earnings Tests:

   Staff recommended requiring earnings tests of deferred balances for all AACs. This recommendation aimed to align the Company's Return on Equity (ROE) with the associated level of risk in cost recovery.

3. Move Pilots into Base Rates:

   Staff recommended the Commission consider shifting mature pilot

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1 Staff/2200, Dlouhy – Muldoon – Scala – Stevens/31.

programs from separate AACs into base rates, making the associated costs subject to the regular ratemaking process. By incorporating these costs into the base rates, a comprehensive evaluation of overall costs and fairness in cost recovery can be achieved.

Together, these measures aim to address concerns regarding the proliferation of deferrals and AACs both administratively and as a ratemaking mechanism, as well as the potential imbalanced transfer of cost recovery risk from customers to shareholders.

Q. What did Staff recommend regarding the need for deferrals with AACs in Opening Testimony?

A. Given that this is essentially a legal issue, Staff will primarily address the roles of deferrals with AACs in brief. However, in Opening Testimony, Staff outlined its view that AACs with a backward-looking aspect that can result in changes to rates require a deferral.[2]

Q. What did parties write on this issue in opening testimony?

A. Oregon Citizens' Utility Board (CUB) submitted voluminous testimony on the topics of single-issue ratemaking, trackers and AACs, and the role of deferrals with AACs.[3] After discussing the interplay between risk and the deferrals, trackers, and AACs as they relate to the Commission's role in setting just and reasonable rates, CUB presented a set of recommendations:

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2 Staff/2200, Dlouhy – Muldoon – Scala – Stevens/20.

3 CUB uses the terms "tracker" and "AAC" in its opening testimony whereas Staff refers to both items as an AAC. Staff will use only the term "AAC" in its testimony when not quoting another party noting that any recommendations Staff makes applies equally to AACs and trackers.

- Require utilities to file an annual report that lists every AAC, deferral, and tracker along with the cost and purpose of each of these mechanisms.[4]
- Institute a sunset date of three years for all trackers where the Company must justify the continued use of the tracker.[5]
- Presume that each tracker will have an earnings test with a deadband unless the utility can demonstrate to the Commission's satisfaction that there should not be.[6]
- Eliminate Schedule 110, 112, and Schedule 134.[7]
- Move Schedule 138 to base rates.
- Require the Company to justify why Schedule 145 should remain on tariff book in the next rate case.[8]
- Move the costs associated with the Request for Proposals (RFP) Independent Evaluator (IE) and any third-party consultants into base rates rather than allowing them to be recovered through a deferral.[9]

Much like Staff, CUB also argued that AACs require deferrals even where administratively burdensome, but CUB also leaves any legal interpretation for briefs.[10]

Q. How did the Company respond to Staff's Opening Testimony on AACs and deferrals?

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4 CUB/200, Jenks/41-42.
5 CUB/200, Jenks/42.
6 Id.
7 CUB/200, Jenks/42-43.
8 CUB/200, Jenks/43.
9 Id.
10 CUB/200, Jenks/46.

A. PGE believes that the CUB's and Staff's concern with the overuse of AACs supports PGE's stance that AACs and deferrals should be separate mechanisms. PGE is also open to working with Staff to consolidate deferrals into a single schedule.[11] PGE disagrees that a true up on an AAC constitutes retroactive ratemaking and reiterates the Company's position in Opening Testimony that combining AACs with deferrals is confusing, inefficient, and unnecessary.[12] Finally, the Company requests that the Commission reject Staff's and CUB's proposals to add earnings tests on all AACs and that the Commission also reject CUB's request to eliminate Schedules110 and 138.[13] PGE supports Staff's recommendation of moving mature pilot programs into base rates, such as the costs associated with the Transportation Electrification (TE) plan.[14]

Q. Has Staff's position changed substantially after reviewing the Company's and parties' testimony?

A. Minimally, Staff moves to support some of CUB's proposals that were not initially made in the Staff Opening Testimony and further align one of Staff's recommendations with CUB that AACs be presumed to have an earnings test. Even where not perfectly in sync, Staff finds that the recommendations and findings in CUB's Opening Testimony on AACs are largely in line with Staff's position. In particular, Staff also supports approaching earnings tests as a

[11] PGE/2900, Ferchland – Macfarlane/3.
[12] PGE/2900, Ferchland – Macfarlane/4.
[13] Id.
[14] PGE/2900, Ferchland – Macfarlane/13.

default part of an AAC that has a retroactive component except where the Commission has directed otherwise; specifically, unless the Company, Staff or stakeholders can sufficiently demonstrate to the Commission that there is cause for an exception. Staff further supports requiring an annual filing from the Company detailing all items recovered through deferrals, AACs and trackers. This recommendation includes a small clarification from Staff's Opening Testimony where Staff advocated that all AACs with a retroactive component have earnings test as Staff does expect there to be instances where application of an earnings test warrants some discrimination, as afforded by the applicable law.

Q. Do you believe that the Company adequately responded to Staff's and stakeholders' issues in its Reply Testimony?

A. No. Staff found various places where the Company either seemed to misinterpret portions of Staff's Opening Testimony or missed the point. Staff will describe these items in greater depth in this testimony.

Staff is generally unconvinced by the Company's Reply Testimony and reiterates its recommendations in Staff Opening Testimony for an increased use of earnings tests, moving pilots into base rates, consolidating AACs into a single schedule, and the need for a deferral in AACs with a retroactive component. In reasserting these positions, Staff feels the need to restate its argument that timely recovery does not mean risk-free recovery. The Company seems to ignore this key argument in its Reply Testimony.

Additionally, both Staff and CUB acknowledge the administrative burden of requiring a deferral for to implement AACs with a retroactive component, but, as argued previously, deferrals are statutorily required to make retroactive recovery of costs is permissible. Further, Staff's recommendation to consolidate AACs into a single schedule is intended to be an alternate way to reduce administrative burden.

Q. How should the Commission decide the parameters of the earnings test for different AACs or when an earnings test should be waived?

A. Staff notes that the Commission currently determines whether and how to apply an earnings test on a case-by-case basis. Staff recommends the Commission continue to determine the parameters on a case-by-case basis but start with the assumption an earnings test as a check on under or over recovery is appropriate for all AACs. Staff's recommendation to apply this default assumption regarding earnings tests is meant to re-express the burden of proof upon the utility as a better balance of customer and shareholder risk. In making this recommendation, Staff believes that broad guidelines should be outlined to establish situations in which it may be appropriate to waive an earnings test on an AAC.[15]

Q. What situations does Staff believe would warrant waiving the earnings test on an AAC?

[15] In the discussion regarding applying an earnings test to an AAC, Staff is referring to the look-back true-up portion of the AAC and not the forward-looking component.

A. Staff has identified a few situations in which it could make sense to waive an earnings test.

- AACs that are used to collect revenue from one customer or customer class and transfer it to another customer or customer class in a revenue neutral manner. In this case, there is no additional revenue being captured by the Company, only a redistribution of revenues among the various classes. Staff views this to be more akin to an issue of determining a fair rate spread issue than an issue of balancing risk between shareholders and customers and so a transfer mechanism should not trigger an opportunity to raise or lower overall revenues.
- AACs that are used to collect or refund a particular percentage or quantity of revenue between the Company and customers through a legislatively mandated process. In this case, Staff finds that an earnings test could create a mismatch between the legislatively mandated value required and the amount actually collected that contradicts the spirit of the law at the very least.
- AACs where Staff, stakeholders, or the Company believe that waiving an earnings test creates significant operational efficiencies or aligns incentives in a productive manner.

Staff notes that this list is not meant to be exhaustive but rather identifies some of the situations where waiving an earnings test may warrant consideration.

Q. What items from the Company's Reply Testimony that Staff would like to address or correct?

A. Staff will respond to the following observations or arguments made by the Company:

- An earnings test is inappropriate because legislative language often requires "timely" or "complete recovery" of costs at issue.[16]
- Staff's arguments regarding rate impacts narrowly focus on just residential customers instead of all cost-of-service customers.[17]
- Staff's focus on the percentage growth of dollars recovered under AACs, as compared to all revenue collected from ratepayers, rather than growth on a dollar basis, is a weakness of Staff's argument.[18]
- Staff's inclusion of the basic charge in the workpapers associated with its analysis of financial impact of AAC's is misleading and leads to incorrect analysis.[19]
- Staff's inclusion of Schedule 109, which funds the Energy Trust of Oregon, in its analysis of the financial impact of AACs does not provide a fair comparison.[20]
- AACs do not shift traditional risk allocation from the Company's shareholders to its ratepayers.[21]

Q. What issues does Staff take with the Company's statement that the legislative language requires "timely" or "complete recovery"?

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16 PGE/2900, Ferchland – Macfarlane/8.
17 PGE/2900, Ferchland – Macfarlane/10.
18 PGE/2900, Ferchland – Macfarlane/9.
19 Id.
20 PGE/2900, Ferchland – Macfarlane/11.
21 PGE/2900, Ferchland – Macfarlane/12.

A. In its Opening Testimony, Staff cites three bills from the legislature that have language that has been used to create AACs in Oregon, namely SB 762, HB 2021, and SB 1547. As far as Staff can discern, none of these three bills mandate the Commission must ensure "complete recovery" of costs or include specifics on the timing of recovery. Staff feels it important to reiterate our stance in Opening Testimony that "timely" cost recovery does not mean "risk-free" cost recovery.[22]

Q. How does Staff respond to the Company's criticism that Staff focuses its analysis only on residential bill impacts of AACs?

A. Staff conducted its review focusing on the residential bill impacts because that constituted the largest customer class and because the issue of single-issue ratemaking and the use of deferral, AACs, and trackers was thoroughly addressed by CUB, which represents residential customers.

Q. The Company criticizes Staff's analysis of focusing on percentage growth rate rather than year-over-year dollar growth rate. How does Staff respond?

A. Staff believes it to be more appropriate to focus on percentage growth rather than year-over-year dollars. This is not unlike the analysis that the Company presents when it talks about overall rate increases, power cost rate increases, load growth, or a variety of other circumstances. While the Company does point out that the year-over-year dollar growth of AACs is far less than the total

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[22] Staff/2200, Dlouhy – Muldoon – Scala – Stevens/6.

revenue forecast,[23] this point completely sidesteps the concerns brought up by CUB in the public meeting regarding ADV 1453, namely that AACs are becoming a much larger piece of the overall ratemaking pie. Measuring proportions is not done in absolute dollar terms, but rather by comparing proportions.

Q. The Company notes that Staff's data includes a column for the basic charge as a part of overall revenue requirement, which is part of base rates. How does Staff respond?

A. Staff is very aware that the basic charge is part of base rates and any graph that compares the growth of residential revenue requirement, residential base rates, residential AAC revenue, or any other iteration of those items properly accounts for the basic charge as part of base rates. Staff compiled this data directly from the Company's response to Staff DR 328, which separately calculates revenue from the basic charge. The work paper was used in a variety of analyses for Staff's Opening Testimony, so Staff chose to leave the basic charge as a separate column of the workpaper submitted with its Opening Testimony.

Q. The Company recreates Staff's analysis while removing Schedule 109 on the basis that it meets the Staff's criteria of a useful AAC. How does Staff respond?

A. Staff agrees that Schedule 109 (Energy Efficiency Funding Adjustment) meets the criteria of a useful AAC, but Staff also disagrees with the characterization

[23] PGE/2900, Ferchland – Macfarlane/9.

that just because something is useful, it should be removed from the analysis. By the same logic, Staff could remove any number of items from the Company's base rates that it deems "useful" to artificially paint a picture of AACs increasing even more dramatically than base rates over the last decade. Instead, Staff believes it to be more appropriate to compare the use of deferrals with AACs in aggregate to base rates or power costs as a whole. In this way, the Commission can be better appraised of how AACs factor into overall revenue requirement and be more mindful of where it may be more appropriate to move items to base rates, institute earnings tests on deferrals with AACs, or pursue some other action that maintains a fair balance of risk between shareholders and customers.

Further, Staff notes that even when the Company removes AACs that it believes Staff would find "useful" and correcting for other items such as the Residential Exchange Program – which is an AAC that does not have an attached deferral – there are still years in which AACs correspond to over two percent of forecasted revenue.[24]

Q. Why doesn't the Company believe that the proliferation of AACs shifts the traditional allocation of risk from shareholders to ratepayers?

A. The Company states that if it were under a regime of using only forecast-based ratemaking, customers would be at greater risk of over-paying or under-paying

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[24] PGE/2900, Ferchland – Macfarlane/11.

costs. The Company states that using an AAC allows the Company to reduce the risk through truing up these costs.[25]

Q. Does Staff agree with this assessment?

A. No, for two reasons. First, a utility that has a program with an AAC would have less incentive to tighten its belt if its costs were running over but would have plenty of incentive to find ways to spend leftover money on projects if a budget surplus was expected.

Second, as Staff points out in its opening testimony, the lack of an earnings test on many of the Company's AACs means that the Company may have strong overall earnings but still be able to recover any cost overruns related to items with AACs.[26] Staff views the Company's earnings to be fungible and believes that recovering additional costs for an AAC-funded program while earnings are reasonable overall provides an unfair allocation of risk towards customers.

Q. To this point, Staff has only spoken about the unfairness in scenarios where the Company is overearning but needs to recover additional funds for an AAC with cost overruns. Does Staff believe it to be unfair to not refund customers through an AAC if a particular program over-collects, but earnings are sufficiently low?

A. Yes. As Staff has just stated in the previous question, Staff believes that earnings are fungible. In a world where everything is recovered through base

[25] PGE/2900, Ferchland – Macfarlane/13.
[26] Staff/2200, Dlouhy – Muldoon – Scala – Stevens/17-18.

rates, it is entirely possible for a certain programs revenues collected through rates to exceed the program costs for a year while overall revenues are below expectations. Therefore, Staff understands and finds it entirely reasonable that funding these programs through base rates or AACs with earnings tests attached to them would not result in a refund to customers assuming that there is a prudent reason for the funding mismatch. Staff views this to be another example of a way to more fairly balance risk between customers and shareholders than the current status quo of many AACs without application of an earnings test.

Q. The Company disagrees that earnings tests should be added to Schedules 150 and 153, citing that it violates legislative mandates requiring 0.25 percent of revenues set aside for TE in Schedule 150 and contemporaneous recovery of costs in Schedule 153.[27] How does Staff respond?

A. Staff disagrees with the Company for many of the same reasons pointed out above. Schedule 150 concerns both the recovery of costs and matching the costs up to actual spending on TE investments. Staff believes it to be reasonable and feasible to require an earnings test on the balancing account with conditions on the spending portion. Regarding Schedule 153, Staff reiterates that it does not believe that contemporaneous recovery of costs necessarily means contemporaneous and *risk-free* recovery of costs. As such, an earnings test would appropriately allow the costs to be recovered

[27] PGE/2900, Ferchland – Macfarlane/16.

contemporaneously and leave some small amount of cost recovery risk on the look-back portion of the AAC that would be based on the Company's overall earnings and their spending on the CBIAG.

Q. The Company also makes the claim that its risk profile is actually heightened through the use of AACs as opposed to putting these items into base rates given changes to the utility industry.[28] How does Staff respond?

A. Staff believes that PGE completely misses the point of the voluminous testimony submitted by Staff and CUB on the issue. At no point has Staff advocated putting *all* AACs into base rates nor has Staff advocated that the utility industry has remained the same.

Once again, Staff must reiterate that AACs *without application of an earnings tests* gives the Company a guaranteed stream of revenue that is almost entirely insulated from both its own internal operations and any outside forces that affect other industries whose stocks would be comparable to the Company's. Staff continues to contend that the quantity of AACs is too high, but Staff has repeatedly also said that AACs do indeed have a place in ratemaking.[29] However, Staff finds that the Company's claim that removing AACs would increase risk is poorly justified and entirely ignores the risk shifting that occurs when AACs are added, and earnings tests are not put in place.

Q. Does this conclude your testimony?

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[28] PGE/2900, Ferchland – Macfarlane/16.
[29] Staff/2200, Dlouhy – Muldoon – Scala – Stevens/2.

A. Yes.

CASE: UE 416
WITNESSES: CURTIS DLOUHY,
JULIE JENT,
ROSE PILEGGI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3800

Rebuttal Testimony

August 22, 2023

Q. Please state your names, occupations, and business address.

A. My name is Dr. Curtis Dlouhy, Ph.D. I am an Economist and Senior Utility Analyst employed in the Strategy and Integration Division at the OPUC.

My name is Julie Jent. I am a Senior Economist in the Energy Costs section of the RSUP Program of the OPUC.

My name is Rose Pileggi. I am a Senior Utility Analyst at the OPUC in the Energy Costs section of the RSUP Program at the OPUC.

All of the above Staff have the same business address, which is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your each of your expertise and educational backgrounds.

A. Our witness qualifications statements can be found in Exhibits Staff/101, Staff/301, and Staff/1801.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address intervenors' opening testimonies and the Company's Reply Testimony on PGE's Power Cost Adjustment Mechanism (PCAM). It is worth noting that Staff addressed each of the Company's four proposals (remove the earnings test, remove the deadband, implement a 2.5% rolling cap, and recover all RCE-related costs) extensively in our Opening Testimony. Rather than rehash these issues with the same intensity, this testimony focuses on responding to the Company's Reply Testimony.

Q. Did you prepare any exhibits for this testimony?

A. We did not prepare any new exhibits for our Rebuttal Testimony. However, please refer to our previously prepared exhibits for Staff/2300. Staff prepared Exhibit 2301 for PGE's response to non-confidential DRs, 2302 for PGE's response to confidential DRs, and Exhibit 2303 for Staff workpapers.

Q. How is your testimony organized?

A. Our testimony is organized as follows:

ISSUE 1. ROLE OF REGULATION AND THE PCAM PRINCIPLES

Q. When were the PCAM and its governing principles established?

A. In 2005, the Commission established a set of governing principles for balancing risk between PGE and customers.[1] These principles were reiterated when the Commission adopted the original PCAM in Order No. 07-015.[2] However, as the Oregon Citizens Utility Board (CUB) detailed in its Opening Testimony, "the methodology of the PCAM and the Commission's power cost recovery principles date back to the Western Power Crisis in 2001."[3]

Q. Please summarize PGE's testimony on the general goals of regulation.

A. PGE largely responds to CUB's arguments on business risk and shareholder equity.[4] PGE agrees with CUB that one of the goals of regulation is to impose outcomes and attributes of competitive markets on regulated utilities, with an emphasis on economic efficiency.[5] However, the Company goes on to describe how utilities (i.e. the regulated utility model) provide an essential service and are therefore at odds with aspects of the competitive market. PGE wraps up its discussion by stating, "Nowhere does the Commission identify the application of all competitive market outcomes on electric utilities as among its goals."[6]

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1 *In the Matter of Portland General Electric Company, Application for a Hydro Generation Power Cost Adjustment Mechanism*, UE 165, Order No. 05-1261 (December 21, 2005).

2 *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, UE 180, Order No. 07-015 (January 12, 2007).

3 See CUB/200, Jenks/9-18 for an extensive discussion on the history of the current PCAM.

4 PGE does not directly quote CUB, AWEC, nor Staff in their Reply Testimony.

5 PGE/2800, Sims – Outama/4.

6 PGE/2800, Sims – Outama/5.

Q. What is Staff's initial response to this section?

A. It appears that PGE mischaracterizes CUB's argument as nowhere does CUB suggest that all competitive market outcomes should be applied to utilities. Staff feels that it is important to highlight the following arguments from CUB's Opening Testimony:

1. Customers are captive to utilities as they cannot go to other producers and therefore must rely on regulation as a substitute for market discipline;[7]
2. Risk should be balanced between shareholders and customers (hence a higher Return on Equity (ROE) is warranted for a greater level of risk);[8] and
3. The purpose of regulation is to set just and reasonable rates and protect customers from the abuses of for-profit utilities.[9]

In general, Staff supports these points offered by CUB and believes most of the arguments made in PGE's Reply Testimony unfairly sidestep CUB's actual arguments.

Q. What additional evidence does PGE provide to rebut CUB's arguments regarding the goal of regulation?

A. PGE references Staff's proposal of a balancing account to capture variances in routine vegetation management (RVM) to demonstrate how parties rely on regulatory tools beyond test year forecast pricing for recovery of certain

7 CUB/200, Jenks/2.
8 CUB/200, Jenks/2-3.
9 CUB/200, Jenks/4.

costs.[10] Even though both the PCAM and the proposed balancing account share some common features, Staff finds that PGE ignores some important differences between the two regulatory tools.

Q. What differences does Staff believe PGE ignored?

A. First, Staff notes that the scale of two mechanisms are very different. The forecasted value of expenses to be covered by the RVM are much smaller in magnitude[11] while the PCAM deals with variances of overall power costs, which start from a baseline forecast of well over $500 million.[12] Staff believes it is naïve to apply the same regulatory tool to items so different in scale without scrutiny or sets of controls to fairly match the scales of the items. PGE seems to have ignored this key factor in its PCAM Reply Testimony, clearly omitting the fact that it opposes everything but the balancing account in its Reply Testimony on the RVM mechanism.[13]

Second, the Company completely ignores the interplay between the proposed RVM balancing account and Staff's Performance-Based Ratemaking (PBR) proposal associated with the account when comparing Staff's RVM proposal to the PCAM. The only similarity is that much like how the PCAM was not designed to be a perfect pass through of any power cost variance, Staff's proposed RVM mechanism is not a perfect pass through of vegetation management expenses.

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10 PGE/2800, Sims – Outama/5.
11 See Staff/2000, Stevens/18 which cites Bekkendahl – Jenkins/12-13.
12 See the Company's initial filing of UE 423 on June 30, 2023.
13 PGE/2200, Bekkedahl – Putnam/3.

Lastly, PGE's fixation on the RVM balancing account in testimony while failing to respond to any of CUB's or Staff's concerns about risk sharing does nothing to demonstrate any regulatory inconsistency within the Commission.

Q. What position does PGE take regarding the role of the shareholder in regulation?

A. PGE starts off by *mostly* agreeing with CUB that, "the role of the shareholder is to absorb risk and that is the reason the investor-owned utility model of service exists relative to public power that must employ either full true ups to all costs and/or reserve funding mechanisms."[14] PGE further points out that investors are not comparing PGE to public power entities for investment purposes and therefore it is a better regulatory policy to align the risk profile of PGE to its peers. PGE ends by explaining why shareholders would still face risks with its proposed PCAM in the form of disallowances, inflation, changes in costs of capital generally, and the risks of new regulations and mandates.

Q. Does Staff find this argument compelling?

A. No. Staff believes that PGE is not describing the full picture or putting investments into the correct context. As CUB pointed out, over the years PGE has made a number of doomsday assertions that have never come to fruition. Most relevant to this discussion, the PCAM did not lead to a credit downgrade for PGE and these rating agencies have not exclusively preferred less shareholder risk.[15]

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[14] PGE/2800, Sims—Outama/6-7.
[15] CUB/200, Jenks/18-19.

Q. Does the Company consider any of the main arguments brought up by Staff and other parties that support keeping the current PCAM principles and rejecting PGE's modifications?

A. No. The Company reiterates its initial arguments for updating the PCAM principles in its Reply Testimony but fails to address many of the proposals and arguments that were brought up in Staff and intervenors' opening testimonies, such as:

- Staff acknowledgement of new business risk, Reliability Contingency Events (RCEs) and recommendation that costs associated with this new business risk be included in the NVPC forecast.[16]
- Staff's argument that the current deadband is small relative to the Company's earnings and any extraordinary event – and likely many ordinary events by virtue of its small size – are expected to fall outside of that.[17]
- Staff's argument that PGE's proposal to remove any earnings tests associated with NVPC is inconsistent with PGE's touting the rollout of low-income rate design and DEI and PGE's earnings test proposal shifts risk of unexpected power costs and resulting rate changes to the same customers the Company claims to be protecting.[18]

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16 Staff/300, Dlouhy/14-28 which discusses some issues with the current methods used in RCE forecasting but does not oppose the RCE forecast itself.
17 Staff/2300, Ahmed – Dlouhy – Jent – Pileggi/11.
18 Staff/2300, Ahmed – Dlouhy – Jent – Pileggi/13.

- CUB's argument that the ratio of PGE's deadband – a proxy for business risk allocated to shareholders – relative to its rate base has declined by 5-fold over the last 20 years due to the overall growth of PGE's rate base.[19]
- AWEC's testimony that the PCAM has been functioning as intended and has provided PGE with adequate protection against volatility in power costs while also providing PGE with the opportunity to earn a reasonable return.[20]

Q. Has the Commission expressed openness to considering changes to the PCAM in light of HB 2021?

A. The Commission expressed openness to evaluating regulatory reforms to ensure balanced implementation of HB 2021, but to Staff's knowledge, the Commission has not explicitly mentioned changing the PCAM for this purpose.[21] In 2020, the Commission mentioned possible review of PacifiCorp's PCAM in 2024, but did not mention HB 2021 as a driver:

> At the same time, other PacifiCorp-specific power cost issues are destabilizing, with a transition to nodal pricing underway, new TAM and IRP models, and the company's work on the MSP framework issue of new resource assignment that may alter the intrastate dynamic allocation of power costs based on load. We can imagine looking at our PCAM parameters in the future when we consider these other significant power costs

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19 CUB/200, Jenks/26.

20 AWEC/200 Mullins/24.

21 See Oregon Public Utility Commission 2023-2025 Strategic Plan, Goal 1 - Short-term Objectives (2023-2025) ("Incorporate significant recent legislative direction (e.g., HB 2021, HB 2475, HB 3141) and increased scope of responsibility from the rapid energy transition by adapting planning oversight and ratemaking to consider climate change, community benefits, equity and environmental justice, providing intervenor funding, and other new issues, including by evaluating performance-based regulation and other appropriate regulatory reforms.")

(around 2024), but this year is not the appropriate time for a redesign."[22]

[22] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, UE 374, Order No. 20-374, pp. 129-30, December 18, 2020.

ISSUE 2. CHANGES IN POWER COST VOLATILITY

Q. In its Reply Testimony, the Company discusses how the changes in power cost volatility warrant changes to the PCAM. Can you summarize some of the finer points of the Company's arguments?

A. Yes. First, the Company states that the push towards renewables in both Oregon and the West have increased price volatility. In supporting its proposed changes to the PCAM, the Company states that Staff's focus on annual power cost figures largely hides this volatility.[23]

Second, the Company states that the prior Western energy crisis cited by Staff is not comparable to the current energy landscape, as that was largely a transitory increase in volatility.[24]

Third, the Company states that the emerging Western markets such as the EIM and EDAM will not solve for all volatility.[25]

Fourth, the Company states that the PCAM should be updated even if shocks such as COVID and the Ukraine War are purely transitory. PGE also notes that some of these effects likely aren't transitory, such as the COVID-induced increase in working from home.[26]

Fifth, the Company claims that resource development will not mitigate volatility, observing that a 4-hour battery has a 45 percent ELCC.[27]

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23 PGE/2800, Sims – Outama/12.
24 PGE/2800, Sims – Outama/13.
25 PGE/2800, Sims – Outama/14.
26 PGE/2800, Sims – Outama/15.
27 PGE/2800, Sims – Outama/16.

Sixth and finally, the Company disagrees that improving forecasting methods is a solution for resolving power cost volatility due to the error and uncertainty in this era of rapid energy changes.[28]

Q. Regarding the Company's first critique, does Staff agree that energy volatility has increased.

A. Yes. Staff has not disputed this. In Staff's Opening Testimony in support of including RCE's in the NVPC, Staff notes that price spikes are becoming more commonplace.[29] Despite what the Company claims, Staff does not believe this means that using annual data is improper for the PCAM. In fact, Staff finds that annual power cost data is actually a better suited comparison for PCAM purposes that intra-month, intra-week, or intra-day volatility.

Q. Why does Staff believe that annual power cost data is a more suitable point of reference than the volatility cited by the Company.

A. Put simply, the PCAM is meant to adjust for *annual* variation and smooth out any offsetting effects of positive price swings in some days with negative price swings in other days. Therefore, Staff believes that when evaluating the appropriateness of the PCAM, it is best to focus on annual data.

Q. Regarding the Company's second critique, does Staff agree with the Company that the comparison to the previous Western energy crisis is improper due to its transitory nature?

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[28] PGE/2800, Sims – Outama/17.
[29] Staff/2300, Ahmed – Dlouhy – Jent – Pileggi/5.

A. No. As was pointed out by parties, the PCAM was created in response to the volatility that arose from the Western energy crisis in the early 2000s.[30] The Company notes that the crisis was resolved within 18 months due to natural gas resource buildout whereas the energy volatility today is expected to persist well into the future.[31]

Staff finds that the Company again misses the point in this comparison. The fact that the PCAM was created in response to the Western energy crisis already indicates to Staff that the Commission was interested in creating a mechanism to deal with future volatility similar to what we are currently experiencing in markets. The fact the original volatility that prompted the creation of the PCAM subsided does not mean the PCAM is an inappropriate tool to address volatility.

Q. Regarding the Company's third critique, does Staff believe the Western EIM and EDAM will solve for all volatility?

A. No. Again, the Company seems to sidestep two key Staff arguments that we've already introduced:

1. The deadband is currently much smaller relative to rate base than it was when the PCAM was introduced, meaning that the Company's shareholders are already enjoying greater insulation from sustained price shocks than was initially intended by the PCAM.

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30 CUB/200, Jenks/9.
31 PGE/2800, Sims – Outama/13.

2. Staff does not believe in perfect insulation from price volatility risk, which is why the PCAM is structured in its current fashion.

The Company misses another key point when bringing up the Western EIM and the EDAM. The Company did not even mention its involvement in the Western Resource Adequacy Program, which requires both a seven-month forward showing to demonstrate that its members are expecting to meet load and an operational program to share load in capacity shortfall events. Staff expects this to provide yet another avenue to insulate against volatility.

Q. Regarding the Company's fourth critique, the Company says that transitory shocks such as the Ukraine War or the COVID-induced shift to work from home are likely more permanent and not a good reason to resist changes to the PCAM. Does Staff agree?

A. No. In fact, Staff finds that these transitory changes highlight the that the PCAM is working as intended, both as a way to recover prudently incurred power costs and as a way to smooth out power costs variance on an annual level rather than fixing on the volatility at a smaller time scale.

In the 2021 PCAM, UE 406, PGE was able to recover an additional $26.6 million, which was supported by a stipulation from all parties.[32] In its testimony on the issue, PGE reported a positive Annual Variance of $61.6 million attributed largely to sustained heat events during the summer of 2021.[33] In this

[32] Order No. 22-440.
[33] UE 406, PGE/100, Batzler – Cristea/12.

case, the annual variance in power costs threw power costs far enough out of line from expected costs that a recovery was warranted.

However, in the 2022 PCAM filing – a year that was marked by the continued transition to working from home and the Ukraine War – the Company's power cost variance of $23.2 million fell within the deadband.[34] Staff points this out to highlight that focusing purely on the individual factors that cause variance rather than the cumulative annual effects of all the various large and small factors that change overall power costs defeats the purpose of the PCAM.

Q. Regarding the Company's fifth critique, do you believe that the Company's choice to focus on the 45 percent ELCC of a four-hour battery accurately reflects the potential for resource development to mitigate volatility?

A. No, the Company's arguments are creative, but not persuasive. The Company's 45 percent number is cherry picked and ignores the interplay between ELCC, the resource stack, and other potential resource options.

First, it is worth noting that a battery's ELCC is dependent on the other resources on the grid. As a general rule, ELCCs of batteries tend to rise as more intermittent resources get added to the grid. As PGE transitions to a more renewable-heavy resource mix, the ELCC of batteries will also increase thus making them a more attractive way to meet capacity and smooth out volatility.

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[34] UE 423, PGE/100, Batzler – Cristea/12.

Second, even though PGE states that the ELCC of a standalone battery is only 45 percent, they forget to mention that the ELCC of storage paired with renewables often exceeds 100 percent. This can be seen in its response to Staff DR 299, which shows PGE's final 2021 RFP shortlist.[35]

Q. Regarding the Company's sixth critique, do you find the Company's statement that the forecasting changes cannot solve for power cost volatility to be relevant?

A. No. The point of a forecast is to set a baseline from which to judge the variance. To date, Staff is satisfied with the ability of the forecast to do so and has been continually open to integrating updates to the forecast to better reflect expected future outcomes. Neither the power cost forecast nor the PCAM were designed to completely control for any errors or uncertainty, a point which the Company seems to completely ignore throughout its Opening and Reply Testimony. Rather, the forecast is meant to set a reasonable baseline and the PCAM is meant to true up any excessive deviations from that baseline. As Staff has repeatedly stated in its testimony on the deadband, Staff believes that the deadband already gives the Company the ability to recover excessive variances in power costs, particularly given that the deadband has not grown proportionally with the Company's overall revenue requirement.

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[35] Staff/4201, Dlouhy – Jent – Pileggi/1.

ISSUE 3. THE EARNINGS TEST

Q. Does Staff believe that the earnings test belongs in the PCAM and in ratemaking in general?

A. Yes. The earnings test is fair and just by, protecting:

1. Customers from paying for higher-than-expected power costs or deferred amounts when the utility's earnings are reasonable, and
2. The Company from refunding power cost savings or deferred amounts when it is underearning.[36]

The earnings test continues to work as intended by excluding normal variations in power costs from triggering the mechanism. It is also worth noting that Staff advocates for using more earnings tests in Staff Exhibit 4100.

Q. Restate PGE's proposal.

A. PGE proposes to remove the earnings test. It argues for the removal in a section of its Reply Testimony entitled *An Earnings Test on the PCAM is Unnecessary and Might Reduce Customer Credits*.

Q. What support does PGE provide for removing the earnings test?

A. PGE provides the following points to support their proposal:

- An earnings test results in a comingling of different cost elements subject to different rate making cycles.

[36] Staff/2300 Ahmed—Dlouhy—Jent—Pileggi/28.

- If PGE is over-earning and doing so systematically, its proposal ensures that the resulting credits to customers would eliminate nearly all over-earnings.
- Only a few Peer Utilities who are capital competitors are smaller than PGE.
- An earnings test is a solution for a problem that does not exist in practice.

Q. How does Staff respond to the point that an earnings test results in a commingling of different cost elements?

A. Staff agrees, but notes that that is essentially the precise purpose of the earnings test—to look at the Company and its earnings holistically. The idea is that over time these costs, when combined, allow for a proper return on equity for the Company.

Q. How does Staff respond to the point that PGE's proposal would eliminate over-earnings?

A. We do not have a valid counterfactual for what earnings would have been if no earnings test had ever been put in place. PGE assumes that the costs would have been the same, without providing evidence to support this assumption. Also, there would still be the possibility of overearning despite PGEs statement to the contrary. PGE states, "If PGE is over-earning, the Commission could request PGE file a rate case or investigate PGE's earnings."[37] This is not a normal occurrence and is unlikely given the number of utility annual filings and

[37] PGE/2800 Sims – Outama/25.

rate cases each year that the Commission receives. Further, for Staff to open an investigation into PGE's rate levels, Staff would need to be reasonably confident that the over-earnings status is sustained and not a short-lived situation to ensure that the investigation would result in a decrease in rates.

Q. How does Staff respond to the point that PGE is competing against larger peer utilities for capital?

A. Staff does not find the Company's argument compelling. Figure 8 of PGE/1000 Liddle – Villadsen/53 reports information for 26 electric utilities and Figure 9 reports their annual revenues; the charts also include a categorization of regulated or mostly regulated. There are three points to be made, 1. PGE selected which companies to highlight, 2. PGE required that the companies have an investment grade credit rating and a market capitalization of more than $300 million, and 3. The results showed that the electric sample had the same credit rating as PGE despite PGE being a smaller company.[38]

Q. How does Staff respond to the concern that an earnings test is a solution for a problem that does not exist in practice?

A. As stated above, the earnings test is meant to ensure that the total earnings of the company are reasonable. Table 1 makes three points, first, earnings have been overall reasonable between 2003-2022, second, Staff does not know if the table would look the same if no earnings test had been in place, and third, it is impossible for PGE to know whether it is solving for a problem that does not

[38] PGE/1000, Liddle – Villadsen/52.

exist as the reverse seems to be true—a problem is being solved for that is why we do not see it as often.

FIGURE 1: PGE EARNINGS HISTORY

Table 1
PGE Earnings History

Sample Period	2003-2022	Avg. Basis Pts. to Authorized ROE
Years Total	20	-1.36%
Years Under-Earning	16	-1.94%
Years Over-Earning	4	0.94%

ISSUE 4. 2.5 PERCENT ROLLING CAP

Q. Please summarize the Company's Reply Testimony on the 2.5 percent rolling cap.

A. The Company starts by clarifying that the 2.5 percent rolling cap would equate to $58 million of annual power cost variance and therefore only apply to the variance in excess of $58 million.[39] They go on to say that the intergenerational problem is not relevant because these amortizations take place over the course of a couple of years, not between the lifetimes of children and grandchildren.[40]

Q. How do you respond to the Company's Reply Testimony on the rolling cap?

A. Staff appreciates the comparison of the 2.5 percent rolling cap to actual dollar amounts. However, Staff is still unconvinced for two reasons. First, when taken in the context of the current deadbands, a rolling cap of 2.5 percent would never have been triggered and is thus unnecessary. Second, Staff disagrees with the Company's clarification of the intergenerational equity concerns.

Q. Why do you disagree with the Company's characterization of the intergenerational equity concerns?

A. Staff believes that the Company is improperly interpreting "generation" to mean a family generation. If interpreted this way, the Company would be correct in

39 PGE/2800, Sims – Outama/27.
40 Id.

saying that there are no intergenerational equity concerns as the amortization would likely take place over a couple years.

However, when it comes to utility customers, this is not an appropriate way to define a generation. Instead, a generation should be viewed more as a utility's annual customer base. A customer that helped contribute to any power cost variance in one year may move away from the Company's service territory by the time that the trued-up variance is placed back into rates. In areas with high rental turnover such as a large metro, one would expect that there is a substantial number of customers who would be moving into and out of PGE's service territory. As such, even amortizing over an additional year which could be an outcome of the 2.5 percent rolling cap exacerbates the intergenerational problem.

ISSUE 5. OTHER CONCERNS

Q. What other items from the Company's Reply Testimony does Staff feel it is important to respond to?

A. Staff wishes to respond to the following arguments made by PGE:

1. The Company states that its RCE carve out is reasonable and Staff did not respond to the criteria for calling an RCE. PGE further states that the carve-out prioritizes reliability operations over economic efficiency in a way that should be incentivized.[41]
2. The Company states that its current proposal incentivizes cost management.[42]

Q. Why did Staff not respond to the criteria for calling an RCE?

A. Staff did not respond to these criteria because as we stated in Opening Testimony, Staff does not agree that RCEs should be separately carved out from the PCAM. As Staff has stated throughout this testimony, Staff believes that power costs should be viewed holistically over the course of the year for the purposes of the PCAM, therefore it would be inconsistent to allow perfect recovery of the most extreme days.

Q. Do you agree that the Company should prioritize reliable operations over economic efficiency during capacity shortfall event?

A. Yes, and Staff finds the Company's testimony worrisome. The Company seems to imply that the Company may be incentivized to place economic

[41] PGE/2800, Sims – Outama/24.
[42] PGE/2800, Sims – Outama/22.

efficiency ahead of reliability during capacity shortfall events. Staff is very concerned by this implication and feels the need to reiterate that during a capacity shortfall event, reliability should always be the highest priority.

Staff also believes that the current framework currently aligns with those incentives. We note that the PCAM is structured to refund the Company in the event that its holistic power costs exceed the deadband and has allowed the Company to forecast incremental costs of RCEs in the AUT.

Q. Do you believe that the Company's proposal improves cost management incentives?

A. No. The Company's proposal only requires PGE to absorb (refund) ten percent of incremental (decremental) power costs whereas the deadband allows PGE to keep up to $15 million of decremental power costs and then be subject to a sharing mechanism. While the incentive would not necessarily disappear under the Company's proposal, Staff believes that the current deadband structure provides much stronger cost management incentives than the Company's proposal.

Q. Given everything discussed in this testimony, has Staff's position on the Company's proposed amendments to the PCAM changed?

A. No. Staff finds that the Company has still failed to provide any compelling evidence that the PCAM needs to be changed to adapt to the current energy landscape or that a change would incentivize the Company to act in a more effective manner.

Q. PGE states that, "…PGE shareholders must be provided a premium if the PCAM is not modified…"[43] If PGE shareholders were compensated via a premium on ROE, would there be a significant change to the ROE?

A. No. There have been minimal impacts historically. In response to Staff DR 181, PGE provided the variance on Base PCAM and Actual PCAM over the 2015-2021 PCAMs. The data provided demonstrated that the current deadband construct, roughly -35/+70 basis points (bps) of ROE, did not have any significant impact to overall ROE. Rather, during the 7-year period provided, PGE did not once share its power cost savings with customers. Over this same period provided by PGE, the average annualized customer burden was $3.81 million, and the average annualized Company burden was $3.75 million. The impact of this annualized $3.75 million is roughly 8.7 basis points of ROE for the proposed 2024 rate base.

Q. The Company expressed concern that the earnings test on top of the deadband construct would further hinder PGE's ability to earn its authorized return. Is this demonstrated by the near-term historical data?

A. No. While PGE is subject to an earnings test on amounts outside of the deadband, on an annualized basis, PGE has not demonstrated that this current construct has, in a recent year, caused a significant change to ROE. PGE makes the statement, "Additionaly, [sic] the earnings test of+/- 100 bps of ROE makes it unachieveable [sic] to earn the allowed ROE if the company experiences higher than forecasted power costs because the company would

[43] PGE/2800, Sims – Outama/20, lines 7-8.

only be allowed to share costs with customers 90% up to an ROE that is 100 bps below its authorized ROE."[44] The Company has portrayed the deadband construct as being a significant detractor to its ability to produce its authorized return. The information provided by PGE over the near term did not demonstrate that, in any year provided, the earnings test limited recovery.

Q. Does this conclude your testimony?

A. Yes.

[44] PGE/2400, Villadsen – Liddle/26, lines 5-9.

CASE: UE 416
WITNESSES: Melissa Nottingham and Scott Shearer

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3900

REBUTTAL TESTIMONY
Customer Interval Data, Qualified Monthly Service Charge, Submersible Transformers, and Reconnection Fees

August 22, 2023

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

A. My name is Melissa Nottingham. I am the Consumer Services and Residential Service Protection Fund (RSPF) Manager for the Public Utility Commission of Oregon (OPUC or Commission). Our business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/2401.

Q. Please state your name, and occupation.

A. My name is Scott Shearer. I am an analyst employed in the Rates and Telecommunications Services Section of the OPUC's Rates, Safety and Utility Performance Program.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/2402.

Q. Are you the same Melissa Nottingham and Scott Shearer of Staff that presented testimony earlier in this proceeding?

A. Yes. See Exhibit Staff/2400 and 2403 (Opening testimony and Data Requests and Responses).

Q. How is your testimony organized?

A. Our testimony is organized as follows:

ISSUE 1. CUSTOMER INTERVAL DATA

Q. What is PGE's stance regarding the need to notify customers about customer interval data?

A. PGE states there is not a need to provide additional notification to customers about the availability of interval data as there is a graph of data on customer's monthly bills and customers have full access online through their customer account portal.

Q. What is Staff's stance on notification for customer interval data?

A. While Staff understands this data is available to customers, Staff is concerned that PGE's customers will not know of this change, without direct communication with PGE. Staff believes a one-time courtesy notification is a reasonable expectation to remove a long-standing item contained in PGE's tariff.

ISSUE 2. QUALIFIED FACILITY MONTHLY CHARGE

Q. What is PGE's stance on Staff's request to add clarifying language to the Schedule 300 tariff that the new tariffed rate applies to contracts signed after the effective date?

A. PGE is agreeable to Staff's recommendation, by adding a footnote to Schedule 300 that refers customers to the Schedule 201 tariff for additional information, including the applicability of updated rates to qualified facilities.

Q. Is Staff agreeable to this?

A. Yes. This addresses Staff's concern with information relayed to customers.

ISSUE 3. SUBMERSIBLE TRANSFORMERS

Q. What is PGE's stance regarding removing the option for residential customers to request submersible transformers for aesthetic purposes?

A. PGE states that it is reasonable to remove the option for customers to choose submersible transformers and pay the costs difference.

Q. What additional reasoning is given by PGE for removal of this option?

A. PGE states:

> Staff did not consider the safety issues related to submersible transformers. Submersible transformers pose a higher safety risk to PGE's line crews and higher failure risk than pad mount transformers due to the nature of a below ground vault installation. The crews working on submersible units have tighter clearances during switching and moving wires, which creates a higher risk of injury, and the heavy vented vault lids of submersible transformers have caused injuries. The hinges on the vault lids can rust out and cause the lids to fail when trying to remove them.

Q. Did Staff consider safety related issues in its analysis?

A. Yes. During its review, Staff contacted the Commission's Safety management asking about any concerns with these types of transformers. While there are likely some increased risks, similar to those mentioned in PGE's reasoning listed above, these risks are mitigated by safety protocols that should be in place for PGE workers, as well as training and certifications needed by the electricians performing this work. Additionally, other environmental issues are mitigated by the maintenance and upkeep PGE should be performing on a regular basis.

Q. Did Staff address this in its opening testimony?

A. No. PGE did not mention or bring up any concerns related to safety, either in its application, or in response to Staff's data requests on the issue.

Q. Is PGE's new argument related to safety persuasive?

A. No. While safety, in general, is a valid issue worth understanding in the context of any proposal, PGE's introduction of the safety concern relative to submersible transformers did not include any supporting data, studies, metrics, or evidence to indicate a significant correlation between safety risk and the installation and maintenance of submersible transformers. PGE also did not provide any information that its current safety practices and protocols related to submersible transformers are insufficient to alleviate these concerns.

Q. Has Staff's recommendation related to Submersible Transformers changed?

A. No. As stated previously, Staff agrees with PGE's argument that customers should pay the costs attributable to their choice of a submersible transformer for aesthetic purposes. However, Staff disagrees that the answer is to simply no longer offer the option.

Staff recommends the Commission deny PGE's request to remove the customer's choice to have a submersible transformer for aesthetic reasons. Staff further recommends the Commission require PGE to conduct a cost study on the long-term incremental maintenance costs for submersible transformers along with a cost differential between these and standard Pad-mount transformers and submit the request to update the costs for a submersible transformer in a future rate proceeding.

ISSUE 4. RECONNECTION RATES

Q. What is PGE's stance regarding application of reconnection fees?

A. PGE states after reviewing Staff's analysis, that there is a valid need to reduce the proposed reconnection charges, based on the costs for remote capable meter reconnection. Based on revised numbers, PGE now proposes a fee of $9 for standard reconnection and $23 for after-hours reconnection.

Q. Does Staff support this revised calculation?

A. Yes, in part. Staff believes that the proposed $9/$23 rates are better aligned with estimated cost incurred by PGE to perform these services. PGE's proposal endeavors to strike a balance between the two types of meters and mitigate the disparity between the reconnection costs. Staff still recommends a full costs analysis of the costs to perform reconnections, including, but not limited to: the cost to perform remote disconnections and the cost to perform manual reconnections, accounting for the variance in the administrative rules related to free reconnection (one or two depending on the meter type), and how the Company is ensuring compliance to the administrative rule by properly identifying whether a low income customer as a remote meter.

Additionally, Staff recommends PGE perform a cost/benefit analysis and stakeholder engagement on removing reconnection fees as a per customer charge, in the interest of mitigating the disparate impacts of the energy system. To the extent that energy burden is disproportionately higher within certain customer groups, particularly those that are low-income and identified as environmental justice communities, reconnection fees can have profound impacts exacerbate system disparities. Staff is cognizant of the potential health and safety risks as well as significant financial burden reconnection fees may place on some customers and feels it is reasonable for the Company to explore the current cost recovery practice and engage stakeholders on the impacts of this practice. The analysis, including a summary of stakeholder feedback and any proposed changes to costs, associated rate design, and impact to revenue requirement, should be filed in the Company's next general rate proceeding.

SUMMARY. STAFF RECOMMENDATIONS

Q. Please summarize your recommendations, identifying any adjustments you propose.

A. Staff recommends the following:

1. Direct PGE to communicate with all customers the ability to receive usage data from the Company upon request.
2. Direct PGE to add footnote language to its Schedule 300 tariff that references Schedule 201, related to contract costs only applying to contracts signed after the date the tariffs go into effect.
3. Deny PGE's request to remove the customer's choice to have a submersible transformer for aesthetic reasons and require PGE to conduct a cost study on the long-term incremental maintenance costs for submersible transformers along with a cost differential between these and standard Pad-mount transformers and submit the request to update the costs for a submersible transformer in a future rate proceeding.
4. Accept PGE's revised Reconnection fees of $9 for standard reconnection and $23 for after-hours reconnection, with a requirement to perform a full cost/benefit analysis and stakeholder engagement on the reconnection fee program and application of related Commission rules, to be submitted with any associated proposed changes in the Company's next general rate proceeding.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: Ankum

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 4000

REDACTED
Subject to Modified Protective Order No. 23-039

Fuel Stock and CO_2 Allowances

Rebuttal Testimony

August 22, 2023

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

A. My name is August Ankum, Ph.D. I am the Chief Economist and a founding partner of QSI Consulting, Inc., a consulting firm engaged in this proceeding by the Public Utility Commission of Oregon (OPUC). My business address is 626 Avenue B, Trevose/Feasterville, Pennsylvania 19053.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is found in Exhibit No. Staff/2700 and my witness qualifications statement is provided in Exhibit Staff/2701, respectively.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to issues raised in PGE's Reply Testimony. Specifically, I will rebut PGE's Reply Testimony on fuel stocks and CO2 Allowances.

Q. Did you prepare any exhibits for this Rebuttal Testimony?

A. No; there are no exhibits.

Q. Did PGE's Reply Testimony change your recommendations, provided in your Opening Testimony?

A. No. My recommendations remain as stated in my Opening Testimony. They are summarized in the table below:

Table 1 Summary of recommendations

	Company Filing		Staff		Adjustment	
FERC acct description/ FERC Acct No.	Total Company	OR-Allocated	Total Company	OR-Allocated	Total Company	OR-Allocated
151 / Fuel Stock (Major only)	$ 31,485	$ 31,485	$ 14,071	$ 14,071	$ (17,413)	$ (17,413)
151 / CO2 Allowances	$ 3,021	$ 3,021	$ -	$ -	$ (3,021)	$ (3,021)
Total					**$ (20,434)**	**$ (20,434)**

FUEL STOCKS

Q. Does PGE disagree with your testimony that "fuel stock investments are […] mostly driven by financial considerations"?

A. Yes. PGE correctly quotes Staff testimony that "Staff argues that "PGE's fuel stock investments are not an absolute technical or operational necessity but mostly driven by financial considerations." The Company then goes on to disagree. Specifically, in response to the question "Are rights to North Mist and the resulting fuel stock, which PGE holds at the facility mostly driven by financial considerations", the Company responds with a terse, "No."[1] PGE then goes on to discuss the history of North Mist and the role the storage facility plays in fueling the Company's generating facilities.[2]

Q. Does PGE's reply testimony change your testimony on this issue?

A. No.

Q. Please discuss why it does not.

A. PGE ignores the important qualifier in our testimony to indicate that fuel stock investments are "mostly" driven by financial considerations. Obviously, there are other operational considerations, such as the necessity to ensure fuel (gas) for the Company's generating facilities (PGE's Westside Thermal Plants). However, this does not mean that a fixed level of fuel stocks is predetermined by operational and technical requirements. As is often the case with large and

1 PGE / 1700, Batzler-Ferchland / 30.
2 PGE / 1700, Batzler-Ferchland / 31-33.

complex operations, decisions are made in what is called a process of constrained optimization.

Q. What do you mean by a process of constrained optimization?

A. The process of constrained optimization refers to analyses in which a certain objective, such as the minimization of costs (financial outlays), is constrained by other objectives or requirements. In the instant situation the constrained optimization process concerns minimizing costs (e.g., the financial investments in fuel stock, to be included in rate base) subject to the constraint (i.e., requirement) that there should be an adequate fuel supply for PGE's facilities.

Q. Does PGE perform constrained optimization analyses for much of its operations?

A. Yes. For example, MONET involves constrained optimization analyses, in which various financial considerations are weighed against the requirement to meet demand. At least conceptually, MONET is used to calculate which facilities to dispatch at any given time to minimize costs, subject to the constraint that PGE needs to generate enough electricity to satisfy demand. Given that PGE could meet demand in various ways, including purchasing power, the analyses revolve "mostly" around financial considerations. It is in this sense that fuel stock levels are mostly subject to and determined by financial considerations.

Q. Why is this observation important?

A. The point I am making is that PGE's *reported* fuel stock (included in rate base) is not necessarily predetermined by technical and operational considerations but *subject to financial considerations*. Given the inherent tension between on the one hand the interests of shareholders (increased returns on investments) and on the other hand the interests of ratepayers (lower rates), the just and reasonable level of fuel stocks requires a financial examination.

Q. To be sure, does PGE's own testimony demonstrate that the levels of its fuel stocks investments are driven by financial considerations?

A. Yes. As noted, PGE uses complex *financial* modelling (e.g., MONET) to optimize the dispatch of its facilities, which in turn drive inventory levels. Considering such factors as physical and financial electric contract purchases and sales, and forward market curves for gas and electric power purchases and sales, PGE engages in a constrained optimization process (the minimization[3] of power costs), modelled in MONET, as described by the Company as follows:

> Using data inputs, such as an hourly load forecast and forward electric and gas curves, the model *minimizes power costs* under "normal" conditions by economically dispatching plants and making market purchases and sales.[4]

It is, in fact, readily seen (as discussed in Staff's Opening Testimony) that inventory levels vary throughout the year, not just because the demand for electricity varies throughout the year but also because gas prices and other factors vary throughout the year. There is, as noted, a set of complex interactions between operational and financial considerations PGE is weighing

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[3] An optimization process (algorithm) may involve either the maximization or the minimization of an objective.

[4] PGE / 300, Schwartz – Outama – Cristea / 5.

in setting inventory levels. As PGE itself states (in response to a OPUC data request):

> PGE's fuel inventory test year forecast is derived from PGE's *financial* forecasting modeling software, which summarizes fuel inventory into two primary categories (i.e., oil & gas and coal) for reporting and forecasting purposes. [5] (Emphasis added.)

And further indicating the financial factors driving inventory levels:

> A secondary benefit is the *beneficial economics* of injecting at North Mist during months when plant generation *power prices* are relatively lower and withdrawing to fuel during months when power prices are relatively higher, which PGE forecasts within its net variable power costs and provides to customers as a benefit.[6] (Emphasis added.)

How fuel stock inventories are affected by and adjusted for financial considerations is perhaps most clearly expressed by PGE as follows:

> If a structural change occurs to the *current forward price curve* the storage optimization will be *adjusted*, resulting in a different North Mist inventory level throughout the year.[7]

Staff's Opening Testimony further discusses the countervailing financial considerations in choosing the optimal level of fuel stocks. Specifically, it discusses that PGE is weighing fuel stock *storage* levels against the option of *purchasing* power:

> During a contingency event, like a pipeline disruption that reduces or eliminates gas supply from the regional pipeline infrastructure, […] some portions of the generation (e.g., all of PW2 and up to four Beaver turbines) *would need to be replaced*

[5] Staff/2704, PGE Response to Staff DR No. 642 (d), May 9, 2023.
[6] PGE / 1700, Batzler- Ferchland / 32.
[7]. Staff/2704, PGE Response to Staff DR No. 341, March 16, 2023.

> *with power purchases* at potentially high market prices, because there would be no fuel supply available.[8] (Emphasis added.)

Q. Do PGE's calculations of its fuel stocks (included in rate base) also involve subjective assessments of certain variables, such as prices?

A. Yes. The fuel stock included in rate base is not a "hard" historical figure. Rather, it was calculated by PGE based on variations assumptions. An examination of those assumptions is, therefore, legitimate and in fact warranted in the context of a rate case, such as this one.

In sum, PGE's Reply Testimony on this issue—i.e., asserting that a financial analysis is unwarranted—is misplaced.

Q. Did PGE provide the financial analyses (referenced above) to justify its fuel stocks?

A. No.[9]

Q. Next, does PGE take issue with your discussion of PGE's minimal gas storage in terms of "cushion gas"?

A. Yes. PGE maintains a minimal level of gas balances at North Mist of 1.2 BCF.[10] Per the Company's responses to data requests, this minimal level in turn is bifurcated by PGE into two categories/components.[11] For purposes of discussion, Staff testimony uses the terms cushion gas and contingency gas to

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8 Staff/2704, PGE Response to Staff DR No. 650, April 25, 2023.

9 This is discussed in Staff's Opening Testimony Ankum-Fischer Staff/2700; also see Staff/2704, PGE Response to Staff DR No. 342, Dated March 16, 2023.

10 For example, PGE / 1700, Batzler - Ferchland / 34.

11 Staff/2705, PGE Response to Staff DR No. 647_ Attach A_CONF, Dated April 25, 2023.

differentiate between those two. But PGE takes issue with the term cushion gas, asserting that they do not own cushion gas.[12]

Q. Does PGE's objection make a difference?

A. No. It is, as the saying goes, "a distinction without a difference." PGE identifies the purpose of this fixed inventory of gas as follows: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Although one need not call it cushion gas, this purpose (as described by PGE) is essentially the same as the purpose of cushion gas. It is essentially fixed level of gas (a permanent stock) that is not typically used or tapped into (although this possibility is not excluded in case of emergencies / contingencies.).

Q. Did Staff even recommend a quantity adjustment to the volume (BCFs) of the fixed component that I referred to as cushion gas?

A. No. Staff made no adjustment to the fixed quantity of gas (a part of the 1.2 BCF that PGE declares as a minimal fixed gas stock). The semantics here (i.e., what term to use) make no difference. PGE's Reply Testimony on this is immaterial. In sum, no correction or adjustment is needed to Staff's calculations and recommendations (since no changes for this component of PGE's minimal gas level is needed).

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12 PGE / 1700, Batzler - Ferchland / 34.

13 Staff/2705, PGE Response to Staff DR No. 647_ Attach A_CONF, Dated April 25, 2023.

Q. In fact, do you generally agree with PGE that it makes no sense to "fully deplete all gas resources on a regular basis"?

A. Yes. As PGE puts it: "It would put PGE's system reliability at greater risk. PGE's first and foremost responsibility as a provider of last resort is to meet the energy needs of our customers."[14] I generally agree with this.

Q. PGE dedicates a substantial portion of its Reply Testimony discussing the importance of North Mist storage facilities. Do you in any way question the importance or usefulness of North Mist?

A. No.

Q. However, do you and PGE disagree over what prices to use for valuing the fixed component of PGE's gas fuel stock/inventory?

A. Yes. I recommend the use of *historic prices* for valuing PGE's fixed stock of gas, which is held in reserve so as to never deplete North Mist's storage. The notion is simple: investors should be allowed a return on the monies they have permanently invested in fixed gas stock (given it is used and useful). The reasons for this are discussed in Staff's Opening Testimony (Exhibit 2700, Section Issue 3, Fuel Stock, pages 59 – 62.) There is no need to repeat that testimony here. However, PGE disagrees with this.

Q. Does PGE testify that it values the fixed gas stocks at the average weighted cost of gas ("AWCOG")?

[14] PGE / 1700, Batzler - Ferchland / 34

A. Yes. PGE testifies that "[b]oth PGE's actual and forecast gas reserve balances are calculated using the weighted average method or weighted average cost of gas method (i.e., W ACOG)."[15]

Q. What argument does PGE offer for not using historic prices?

A. PGE argues that it is inconsistent with their accounting practices; the Company also argues that it is based on an allegedly "false" premise that this gas is *not* used:

> This is inconsistent with how PGE values gas for accounting purposes and is based on the *false premise* that this gas cannot be used. PGE has rights on and is able to utilize its full 4.1BCF of storage capacity, and our method for forecasting this stock is consistent with how PGE's gas stock is recorded for financial accounting purposes.[16] (Emphasis added.)

Q. PGE suggests that it may use this "fixed" component of its gas stock. Is this consistent with its other testimony?

A. No. This component was described as fixed.[17] I also just described the purpose that PGE assigns to this component of its gas stock. While it is undoubtedly true that PGE will be able to use the gas in case of an emergency/contingency, that theoretical possibility should not drive how this fixed stock of gas is valued.

Q. Examining the period of October 2022 through December 2023, does PGE's gas inventory even once drop below the level of its fixed gas stock, as PGE claims that it may?

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15 PGE / 1700, Batzler - Ferchland / 37.
16 PGE / 1700, Batzler - Ferchland / 37.
17 PGE / 1700, Batzler - Ferchland / 34

A. No. Not once during this period does PGE's fixed gas stocks at North Mist fall below the level of 1.2 BCF[18]—and, mind you, this fixed level referred to as cushion gas by Staff is in turn only part of what PGE asserts is the minimal level.[19] In other words, this buffer of fixed gas is in fact not projected to be used. Not even close.

Q. Does this mean that it is *inappropriate* to value this fixed stock of gas at forecasted (WACOG) prices?

A. Yes. WACOG is predicated on the notion that gas flows *in and out of storage* and that WACOG captures what the weighted average cost (price) would be. But again, this component of PGE's gas stock is fixed, so this rationale is not applicable.

As discussed in Staff's Direct Testimony, use of WACOG for this component would cause PGE's investors to *over earn at the expense of ratepayers.*

The appropriate valuation metric here is *historic* prices. Once the investment is made, the gas sits in storage. There is no reason to value it at anything but historic prices: it provides investors the precise level of return to which they are entitled. Again, this is discussed in more detail in Staff's direct testimony.

Q. Does PGE assert that you are recommending Henry Hub prices for repricing PGE's fixed gas at historic costs (prices)?

[18] Staff/2705, PGE Response to Staff DR No. 639, Attachment A_CONF, April 25, 2023.
[19] PGE / 1700, Batzler - Ferchland / 34.

A. Yes. PGE states: "[…] using this price information, Staff recommends that […] 'Cushion Gas' should be priced at 'original cost,' which they based on historic prices from Henry Hub."[20]

Q. Is PGE correct that you used Henry Hub prices for historic prices?

A. No; PGE is mistaken. In fact, Staff explicitly states that it did not use Henry Hub prices for this purpose: "Although we do *not use them*, the table below also shows EIA's referenced Henry Hub gas prices *for comparison*."[21] (Emphasis added.)

Q. What historic prices did you use for your adjustment?

A. As discussed in Staff's direct testimony, the adjustment was made with the *actual historic prices* at which PGE acquired its gas in North Mist.[22] Henry Hub prices were shown for comparison, as a national benchmark.

Q. Does PGE acknowledge that EAI uses Henry Hub prices as a *national benchmark* for general trends in gas prices?

A. Yes. PGE's own testimony confirms this: "The benchmark price in natural gas markets is the Henry Hub."[23]

Q. Does PGE note that it does not purchase gas at the Henry Hub locations but at Sumas trading hub in Canada?

A. Yes. PGE notes:

> PGE primarily accesses the Sumas trading hub (located in British Columbia) to deliver gas to PGE's westside thermal generation. […] The prices, which ultimately comprise PGE's

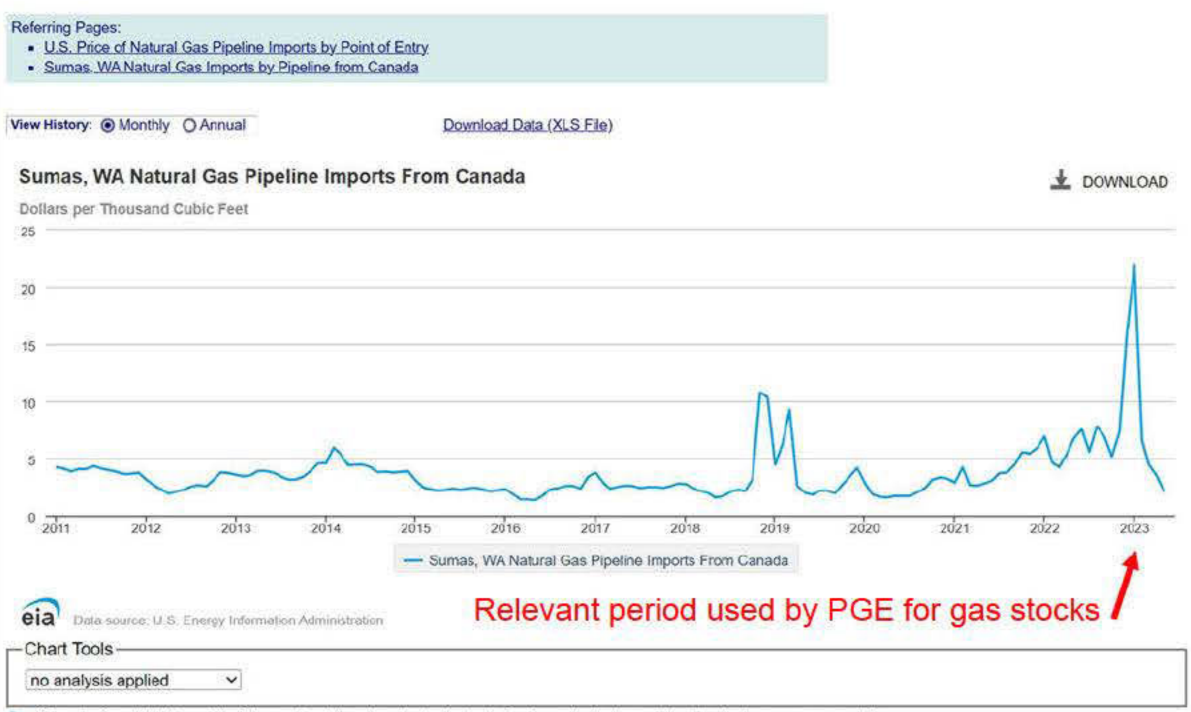
[20] PGE / 1700, Batzler - Ferchland / 35.
[21] Staff/2700, Ankum-Fischer/61.
[22] Staff/2700, Ankum-Fischer/61.
[23] PGE/ 1700, Batzler - Ferchland / 36.

weighted average cost of gas at North Mist that is included in this filing, are from actual gas transactions for actual amounts of gas delivered on the Northwest Pipeline and from PGE's forward gas curve at Sumas for forecast amounts.[24]

Q. Are the Sumas gas prices in line with the price adjustments you made based on the EIA forecast?

A. Yes. The figure below shows the EIA reported prices for Sumas, which are in line with the prices used by Staff to adjust PGE's gas fuel stock.[25] They contrast starkly with the PGE forecasted "WACOG" prices of **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL].**

Figure 1: Sumas, WA Natural Gas Pipeline Imports from Canada



24 PGE/ 1700, Batzler - Ferchland / 35-36.
25 Sumas, WA Natural Gas Pipeline Imports From Canada (Dollars per Thousand Cubic Feet) (eia.gov)

Q. Does PGE criticize Staff for not understanding PGE's fuel stock calculations?

A. Yes. PGE states:

> While Staff references the fact that PGE uses WACOG, they seem to *fundamentally misunderstand* what that means and completely mischaracterize how PGE's gas reserve balance is calculated. WACOG *is not calculating a "replacement cost" nor is it the weighted average price over 15 months*. As described above, it is the total amount that has been paid for the gas, divided by the number of units in storage.[26] (Emphasis added.)

Q. What is Staff's basis for its understanding of how PGE calculates its gas reserve balances?

A. The basis of our understanding is PGE's own testimony and its responses to data requests. Particularly insightful is PGE's response to DR 639, which includes an Excel workbook with detailed calculations and a derivation of the figure ($31,485,000) included by PGE in rate base. As the Company explains:

> For gas inventories, actual period ending inventory is used as the starting basis, which is then adjusted on a monthly forecast basis using a forecast percent change in inventory multiplied against a forecast weighted average cost of gas to adjust the monthly balance. *Confidential Attachment 639-A* provides this calculation.[27] (Emphasis added.)

Q. Does PGE's Excel workbook to DR 639_A CONF confirm your understanding and testimony of PGE's calculations?

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[26] PGE / 1700, Batzler- Ferchland / 37-38.
[27] PGE Response to OPUC Data Request 639, Dated April 25, 2023.

A. Yes. First, the Excel workbook does not use the term WACOG, but rather it simply uses "price."

Next, PGE must be mistaken about its own calculations: most certainly gas reserve balances are indeed calculated by PGE as a *weighted average price* over 15 months.

Q. Please demonstrate that PGE is wrong in not recognizing this?

A. The figure below shows the Excel workbook PGE provides in response to DR 639. It provides a large set of calculations of PGE's fuel stock and gas reserves included in Rate Base, starting with beginning balances of **[BEGIN CONFIDENTIAL]** [redacted] **.[END CONFIDENTIAL]**

Figure 2: PGE's Calculation of Gas Stock in Rate Base

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL] [redacted]

However, this seemingly complex set of calculations can be sidestepped and it readilly collapses into the simple calculation of as an *average price weighted by changes* in gas reserves, as follows:

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

PGE's gas reserves (in rate base) for December 2023 are then readily calculated as shown in the table below:

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Removing **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** included in rate base, which validates the above set of simple arithmetic calculations using a weighted "price" of gas—and, again, price and not WACOG is the term used by PGE in its Excel workbook.

In sum, PGE appears to misunderstand the essence of its own calculations.

Q. Does PGE take issue with your recommendation that fuel stock be based on average monthly balances rather than end-of-year, as PGE is proposing.

A. Yes. PGE states:

> We disagree. Staff is being opportunistic in their average balance argument. PGE's fuel stock, which is a forecasted December 31, 2023 balance, is not in "error" as Staff suggests. It uses the year-end method that is consistent with the rest of PGE's rate base, which is set just prior to PGE' s price effective date. PGE would not anticipate this claim if PGE' s December balance was at the bottom of Staffs sine wave example.[28]

Q. Have you already demonstrated that PGE's proposal would result in PGE's investors overearning.

A. Yes.[29] There is no need to repeat those arguments here. The following figure, however, makes the point yet more clear for gas balances. The blue line represents PGE's proposal to use end-of-year balances (December 2023) for its gas reserves. The red line shows how PGE's gas reserves vary over the course of the year. It is readily seen that under PGE's proposal its investors will end up overearning.

28 PGE / 1700, Batzler - Ferchland / 38-39.

29 In Staff Staff/2700, Ankum-Fischer/64, Staff notes: "December 2023 balances—which are balances in one of PGE's peak months—are significantly higher than the average gas balances for 2023."

Figure 3[30]

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Is your recommendation in this regard conceptually consistent with those of other Staff members?

A. Yes, my recommendation here is consistent with the recommendation of other Staff members in this proceeding.[31]

Q. Does PGE disagree with your recommendation that PGE's contingency gas reserves (for emergencies) are reduced?

A. Yes. In its direct testimony, Staff recommends that PGE's contingency gas be adjusted down for a number of reasons:[32]

30 This figure draws on the data found in DR PGE Response to OPUC Data Request 639, Dated April 25, 2023.

31 Staff/800, Stevens-Young/4-5, referencing Commission Order Nos. 70-797, 74-898, 76-061, and 76-954.

32 Staff/2700, Ankum-Fischer/74.

- There are many ways in which PGE can meet its energy demand in the event of a contingency. Also, in incidental situations of extreme emergencies, North Mist's cushion gas can temporarily be used as well;
- PGE fails to provide adequate support for the likelihood that emergencies will occur during peak days; and,
- PGE fails to provide an analysis that maintaining a permanent stock of contingency gas is cheaper than purchasing power.

There is no need to repeat these arguments here.

Q. Has PGE provided persuasive argument to make you change your testimony?

A. No. To the contrary, PGE's testimony further supports the merit of Staff's recommendation.

Q. Please explain.

A. First, PGE corroborates that the Company has numerous ways of accommodating electricity demand in the event of pipeline outages or other emergencies. This is precisely what Staff argued. For example, PGE states:

> The reality is, if faced with a supply disruption or other reliability event, PGE will likely be doing all three (i.e., dispatching its westside resources that are not fuel limited, dispatching the remaining resources in its resource portfolio, and purchasing power).[33]

Q. But PGE provides a numeric example in an effort to illustrate the importance of its contingency reserves. Is PGE's example complete and persuasive?

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33 PGE / 1700, Batzler - Ferchland / 40.

A. No. PGE provides the following example:

> Consider that PGE has experienced recent market price excursions for power that are above $1,000 per megawatt hour (MWh). This compares to a dispatch cost for Beaver running on stored gas, using PGE's most recent actual WACOG of approximately $59 per MWh (calculated as Beaver's approximate heat rate of 12 multiplied by a WACOG of $4.90). In other words, purchasing market power versus running Beaver from stored gas under the above scenario is *approximately 17 times more costly*.[34] (Emphasis added.)

This example is incomplete and misses the point.

Q. Please explain.

A. PGE example is misleading in that it leaves out many considerations/factors necessary for a complete and valid financial analysis.

First, PGE leaves out accounting for the low likelihood of an emergency actually occurring. Permanently holding gas in reserve for an eventuality is like buying insurance for, say, a car versus a house. While a car is typically cheaper than a house, it may be more expensive to insure because there is a much higher likelihood of an adverse event.

As noted in Staff's direct testimony, when PGE was asked to list examples of outages that warrant maintaining a sizable stock of contingency gas the Company could not provide a single instance of a significant outage that over a sustained period affected the Northwest Pipeline. (The Northwest pipeline provides gas to the Company's North Mist storage facility.) Thus, PGE's example should be considered in the context of the low likelihood of an

34 PGE / 1700, Batzler - Ferchland / 39.

emergency in which PGE would have to purchase expensive power in energy markets. And PGE does not.

Next, PGE mistakenly calculates the cost of purchasing power as "*17 times"* more expensive as running generating facilities from its own stored gas. This calculation is incomplete and thus provides an answer that is wrong.

Given the low likelihood of emergencies, PGE fails to but should consider that PGE will have to store contingency gas likely for *many years* and possibly for a decade(s). This means that PGE—but really the rate payers—will incur the carrying costs of this "contingency" storage. PGE ignores to include this cost in its example.

Further, PGE also ignores that for each MWh of power PGE may have to purchase to meet an emergency, PGE may have had to store gas reserves at *a multiple of one MWh*. That is, by assuming a one-for-one comparison of MWh purchased versus MWh generated from stored contingency gas PGE greatly understates the costs of self-generation in case of an emergency. Depending on the severity and longevity of the emergency (e.g., pipeline outage) the ratio may be one to many, possibly one to ten. That is, for each MWh purchased in an emergency, PGE may have had to hold gas in reserve for many MWhs.

Thus, even at the high price of $1,000 per MWh of purchased power, purchasing power may be the cheaper solution. By analogy, a company would be unlikely to hire an in-house electrician for emergencies even though contracting with one may be very expensive on an incidental basis; this is true if the likelihood of electrical problems in its operations is *low.* By contrast, if a company's operations are routinely plagued by electrical problems, then an in-house electrician may be the cheaper solution. The same dynamics hold here, with respect to PGE's contingency gas, and PGE has failed to adequately capture and analyze the issue.

Q. Is the fact that PGE ignores the carrying costs of "contingency" gas indicative of the divergent interests of PGE and rate payers?

A. Yes. Contingency gas earns a return in the rate base. Thus, PGE is fairly indifferent to carrying excess gas; in fact, the financial incentives are for PGE to favor an excess of contingency gas. Of course, the rate payers' interest is the opposite.

Q. Does the fact that PGE has provider of last resort obligations in itself justify PGE's proposed emergency reserves for gas?

A. No. PGE seeks to justify its emergency reserves by noting that it has provider of last resort obligations:

> As we state above PGE is a provider of last resort. As such, PGE has a responsibility to plan for and be ready to provide continued essential service our customers and community under the most challenging circumstances. This is a responsibility we take very seriously.[35]

Q. Is the provider of last resort obligation an important responsibility of PGE?

A. Yes.

Q. Does it warrant holding emergency gas in reserve?

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[35] PGE / 1700, Batzler - Ferchland / 41.

A. Yes.

Q. But is emergency gas the only way in which PGE can meet its provider of last resort obligations in case of an emergency?

A. No. I have already discussed the myriad ways in which PGE can meet demand in case of an emergency. And PGE has demonstrated the same in its Reply Testimony here. In other words, the importance of provider of last resort obligations is not a blanket justification for PGE's stock of emergency gas.

Q. Do many of the same considerations apply to PGE's emergency reserves of oil?

A. Yes. As demonstrated in Staff Opening Testimony, all of PGE's oil reserves (in rate base) are for emergency purposes. I recommend a reduction of 50 percent:

- With the conversion of Beaver (to a single fuel plant), not all of PGE's oil will continue to be used and useful—if any of it is used and useful at all.
- As with PGE's stock of contingency gas, PGE has various means of meeting electricity demand in emergency situations, other than through contingency oil. These alternatives in themselves obviate the need for PGE's stock of contingency oil that will soon be phased out.

Q. Does PGE's Reply Testimony change your recommendations?

A. No.

Q. Does PGE in fact undermine its own argument for holding fixed oil reserves for emergencies?

A. Yes. Addressing Staff's concern that PGE's oil stock will not meet the standard that it be used and useful, PGE replies as follows:

> While the entirety of Beaver will ultimately lose its dual fuel capability, PGE will continue to have the ability to run Beaver on oil through at least 2025. While a *reduced number* of units can utilize oil, Beaver can *easily burn through PGE's oil stock* over the next few years. Beaver's oil stock is clearly used and useful and will continue to be through PGE's test year and beyond.[36] (Emphasis added.)

Q. How does this undermine PGE's own arguments and rate case filing?

A. PGE itself now testifies that the oil reserves are not for contingencies but may be used up. If that is so, then there is no justification for putting it in rate base as a fixed amount earning a Commission approved rate of return to be paid by rate payers until the next rate case.

Q. You also recommended reducing the price of oil used by PGE to value its oil reserves. Has PGE provided additional justification for using an excessively high price of oil of $105 per barrel?

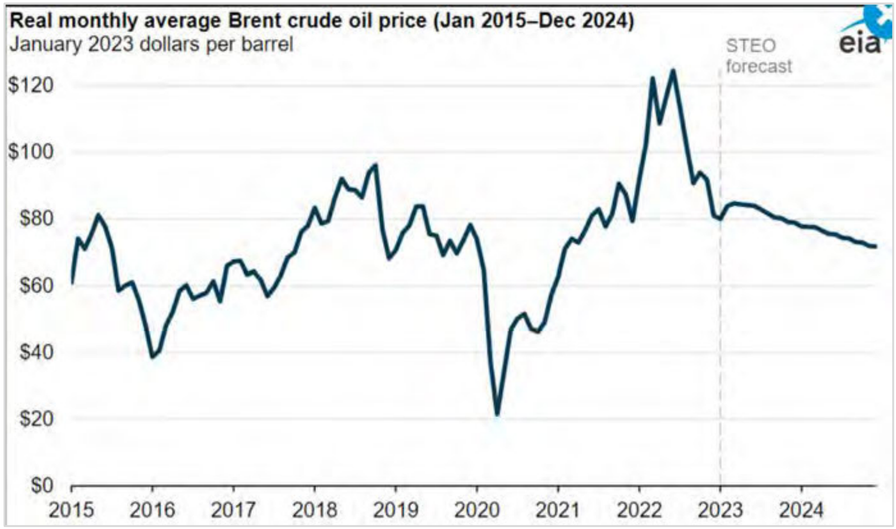
A. No.

Q. Have you already in your Opening Testimony demonstrated that, per the EAI forecasts, PGE's $105 per barrel is excessive?

A. Yes. In Staff's Opening testimony I presented the following chart showing the EAI's oil price forecasts that are well below PGE's $105 per barrel:

[36] PGE / 1700, Batzler - Ferchland / 43.

Figure 4. EIA Oil Price Forecast for 2024[37]



I have addressed this issue in our Opening Testimony[38] and there is no need to repeat those arguments here. Suffice it to say that PGE has not provided additional justification for its much higher price of $105 per barrel.

Q. Has PGE replied to any argument in Staff's Opening Testimony on CO2 allowances?

A. No.

Q. Does this conclude your testimony?

A. Yes.

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[37] EIA forecast: https://www.eia.gov/outlooks/steo/report/BTL/2023/01-brentprice/article.php#:~:text=EIA%20forecasts%20that%20oil%20prices%20will%20fall%20in,we%20expect%20global%20oil%20production%20to%20outpace%20consumption.

[38] Staff/2700, Ankum-Fischer/24.

CASE: UE 416
WITNESS: Madison Bolton & Bret Stevens

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 4100

Rebuttal Testimony
Line Extensions for Large Customers

August 22, 2023

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

A. My name is Madison Bolton. I am a Senior Energy and Policy Analyst employed in the Utility Strategy and Integration Division of the Public Utility Commission of Oregon. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is found in Exhibit No. Staff/1000 and my witness qualification is provided in Exhibit No. Staff/1001.

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

A. My name is Bret Stevens. I am a Senior Economist employed in the Rates, Safety, and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is found in Exhibit No. Staff/2000 and my witness qualification is provided in Exhibit No. Staff/2001. I also submitted joint testimony in Exhibit No. Staff/800 and Staff/2200.

Q. What is the purpose of your testimony?

A. This testimony is to address and further the discussion on the single topic of the spread of transmission and distribution costs caused by large load customers.

Q. Did you prepare any exhibits for this docket?

A. Yes. We prepared Exhibit Staff/4101, which contains non-confidential PGE responses to Staff's data requests.

Q. What is a line extension?

A. PGE's Rule I classifies a line extension as a new or upgraded distribution facility from a point on the Company's existing system.[1] A line extension allowance is the portion of the cost that the Company will pay for the project. Any additional costs in excess of the line extension allowance must be paid by the customer requesting the extension. PGE's current line extension allowance for Schedule 85 and 89 customers is calculated by multiplying a dollar amount by the estimated annual kilowatt-hours (kwh) consumed by the customer. PGE does not currently offer a line extension allowance for Schedule 90 customers.

Q. Does Staff have concerns about PGE's current Line Extension policy?

A. Yes. In Staff/3300, Staff clarified its concerns that certain transmission and distribution projects appear to primarily benefit a small number of large nonresidential customers. However, the costs of the projects are spread across all classes in a manner that does not seem to be consistent with cost causation principles.[2] One potential solution to this issue is to require that upgrades to substations and high voltage distribution infrastructure that

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[1] *See* Advice No. 07-01, PGE Rule I, Subsection 1, Original Sheet No. I-1 (effective Jan 17, 2007), available at: https://assets.ctfassets.net/416ywc1laqmd/6O5exEiUrGrN3R4KugNpgy/a5ed15a22fb947f1d13ceae200875066/Rule_I.pdf.

[2] Staff/3300, Stevens/22-25.

would mainly serve Schedule 85, 89, and 90 customers be subject to the Company's line extension allowance policy. Currently, any significant transmission and distribution upgrades caused by a single customer are handled by a Special Contract. Staff is concerned that the nature of Special Contracts has allowed large customers to pay minimal portions of upgrade costs required to enable their connection. In Attachment A of DR Response 886, PGE only lists five line extension allowances totaling just over $1.8 million for large nonresidential schedules since January of 2020. Comparing these allowances to the projected cost of the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** leads Staff to believe that some of PGE's largest customers are completely avoiding the cost associated with projects dedicated to connecting them to PGEs distribution. By classifying these types of projects as Line Extensions for large nonresidential customers, it limits the amount that the Company is required to pay for the project, thus reducing the amount of costs that are socialized to all other customers.

Q. How does Staff recommend changing the Company's line extension policy?

A. Staff recommends editing Rule I, subsection (1)(A) as follows:

> Line Extensions will be at primary and/or secondary voltage levels. *Except for Schedules 85, 89, and 90,* modifications to transmission or subtransmission voltage facilities or substations are not considered Line Extensions for purposes of this rule and require special contract arrangements. [. . .]

Additionally, Staff recommends altering PGE's Schedule 300 tariff[3] to apply PGE's line extension rules to Schedule 90 using the same rates as Schedules 85 and 89. However, for customers larger than 25 MW, Staff recommends that the line extension allowance be reduced to only the cost of the metering equipment. This is consistent with Pacific Power's (PAC) recent advice filing, ADV 1534/Advice No. 23-016, in which PAC proposes limiting the line extension allowance for large customers. PAC notes that a customer with load greater than 25 MW usually requires its own substation, which the customer should pay for and operate without receiving an allowance.[4] This way, other customers are protected from cross subsidizing massive investments that are specific to a new large load.

Staff argues that these changes will require large nonresidential customers to be responsible for more of the costs associated with their connection to the distribution system, including the cost of substations, reducing the level of costs spread to the residential and commercial classes for infrastructure that primarily serves a limited number of nonresidential customers. Staff is concerned that the "special contract arrangements" referenced in Rule I have resulted in the Company paying for the majority, if not all, of the costs for substation or voltage facilities that would not have been upgraded without the introduction of new load from a select number of large

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[3] *See* Advice No. 22-08, PGE Schedule 300, Eighth Revision of Sheet No. 300-5 (effective May 9, 2022), available at: https://assets.ctfassets.net/416ywc1laqmd/Z9SW1311yNz1OUSoi0Syr/17aaeff01ae3ec499b7ecdae6cb44e33/Sched_300.pdf.

[4] See Advice No. 23-016, Rule 13 Line Extensions, page 2.

customers. Further, Staff is concerned that PGE is simply classifying projects as system-wide costs even though these projects are largely necessitated by one or a small handful of customers.

Q. Does Staff view this issue as only being relevant to certain projects placed in service before the effective date of this case?

A. No. As discussed in Staff/3300, Staff is concerned by the anticipated increase in large load customers expected in PGE's service territory. If left unresolved, this could result in significant cross-subsidization.

Q. Does Staff have any additional recommendations?

A. An alternative to changing PGE's line extension policy in this proceeding would be for the Commission to open an investigation into the issues discussed in Staff Exhibit/3300. Staff believes additional fact-finding could help determine what sizes and types of nonresidential customers have the largest impact on residential rate spread, and whether there are additional safeguards that can be implemented to prevent this level of cross-subsidization. For instance, in DR Response 885, PGE highlights that it has required Minimum Load Agreements (MLAs) from nonresidential customers to recover the construction costs of a project. Staff's understanding of an MLA is that it allows an applicant to forego paying upfront costs for a project by ensuring the costs are recovered later via the revenue generated by that customer. However, it is likely that PGE is not including substation costs in developing the economics of a minimum load agreement and therefore unlikely to hold other customers harmless. Staff recommends examining

MLAs in further detail as part of a line extension investigation to better understand how the Company utilizes these agreements.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: Madison Bolton and Bret Stevens

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 4101

Non-Confidential Responses to Staff Data Requests

August 22, 2023

OPUC Data Request 885

With respect to the Projects P37379, P36373, P36868, P36679, and P36680:

a) Did any customer(s) contribute to the construction of any portion of the project via a special contract arrangement or any other mechanism? If yes, how much was collected? What share of the total project cost did the customer contribute?
b) By schedule, please provide the load from 2010-2023 of customers in the area served by this project.
c) If this project were to be treated as a Line Extension, how much of the cost would have been paid for by the requesting customer? Staff understands that this project is not considered a Line Extension, this question is hypothetical.

PGE Response to OPUC Data Request 885

PGE objects to part b of this request on the basis that it is vague and ambiguous. Staff's use of "area" is unclear. PGE objects to part b and c of this request as it is overly burdensome and requires significant new work. Subject to and without waiving its objections, PGE responds as follows:

a) Yes, for project P37379, PGE required four Minimum Load Agreements (MLAs) from the customer which will ensure PGE recovers the $6.3M in estimated total construction project costs. PGE provided the four Minimum Load Agreements associated with project P37379 in response to OPUC Data Request No. 590.

   Customers are always responsible for civil costs such as permits, vaults, conduits, etc. However, for this project the customer requested that PGE do the civil engineering for which the customer reimbursed PGE. This cost is not included in the estimated project cost described above. See Confidential Attachment 885-A for P37379.

   P36373, P36868, P36679, and P36680 are not customer specific work. There are no customer contributions for these projects.
b) Attachment 885-B provides the load by rate schedule from May 2018 – July 2023 for customers in Hillsboro and Fairview. It is not possible to provide data before 2018 in the amount of time provided to complete this data request. Prior data is stored in a separate database.
c) PGE cannot provide Line Extension Allowances for the projects listed above because these projects were for substation infrastructure which are not considered Line Extensions as described in PGE's Rule I.

OPUC Data Request 886

By schedule, for each year from 2020 to 2022 inclusive, please provide the line extension allowance amounts for each customer, the general basis of the line extension, and the number of applicable customers.

PGE Response to OPUC Data Request 886

Based on conversations with Staff, Staff is requesting Schedule 85 and 89 line extension allowance (LEA) amounts and number customers from 2020-2022 inclusive. Staff is also requesting a summary of the total line extension allowance amounts and number of LEAs by customer class (residential single family, commercial, multi-use, and residential subdivision) from 2020-2022 inclusive.

Attachment 886-A, tab 'Sch 85 and 89 LEAs' provides Schedule 85 and 89 LEA amounts 2020-2022 inclusive. The number of LEAs equals the number of customers. Attachment 886-A, tab 'All LEAs' provides a summary of the total line extension allowance amounts and number of LEAs by customer class (residential single family, commercial, multi-use, and residential subdivision) from 2020-2022 inclusive. Line extension allowance amounts in Attachment 886-A represent the total allowance available for these work orders. If the cost estimate of the project is less than the allowance, then some of the LEA allowance would not be used.

Residential line extension allowances are calculated using a flat rate per dwelling unit as described in Schedule 300-5. PGE provided the workbook and formulas used to calculate nonresidential line extension allowances in response to OPUC Data Request No. 571.

CASE: UE 416
WITNESS: Eric Shierman

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 4200

Rebuttal Testimony

August 22, 2023

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

A. My name is Eric Shierman. I am a Senior Utility Analyst employed in the Resources and Program Development Section of the Energy Resources and Planning Division of the Public Utility Commission of Oregon. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is found in Exhibit No. Staff/1900 and my witness qualification is provided in Exhibit No. Staff/1901.

Q. What is the purpose of your testimony?

A. This testimony addresses and agrees with PGE/2300 on the single topic of the transportation electrification (TE) deferrals in UM 1938 and UM 2003.

ISSUE 1. TRANSPORTATION ELECTRIFICATION DEFERRALS

Q. What did Staff recommend in Opening Testimony?

A. Staff recommended ending the UM 1938 and UM 2003 Deferrals.[1]

Q. Did PGE agree with Staff's recommendation?

A. PGE agreed to end the UM 1938 deferral if comparable cost treatment and recovery is achieved. However, PGE did not agree to end the UM 2003 deferral; requesting it continue until the end of 2024.[2]

Q. Would comparable cost treatment and recovery be achieved for the UM 1938 deferral?

A. Yes. PGE would be able to defer UM 1938 expenses until new rates go into effect. At that time, the amount of expenses budgeted in PGE's TE Plan for this deferral in 2024 will go into base rates. The balance of the tracking account would be amortized to zero through Schedule 150.

Q. PGE/2300 inquired about how the Information and Education component of UM 1938 would be handled. What does Staff propose with respect to the Information and Education component of UM 1938?

A. Staff's recommendation included the entire test year deferral amount that PGE proposed in the Company's UM 2033 TE Budget. PGE's Table 36 in the Company's draft TE Plan does not appear to Staff to have budgeted any deferral funding for Information and Education.[3] Therefore, Staff has not

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[1] Staff/1900, Shierman/22.
[2] PGE/2300, Lawrence-Lynn/2 and 16-17.
[3] See Docket No. UM 2033, PGE, Draft TE Plan, June 1, 2023, pp 150-152.

proposed to move any funding for Information and Education from the UM 1938 deferral to base rates.

Q. What is Staff's recommendation?

A. Staff recommends the Commission discontinue the UM 1938 deferral, and Staff agrees with PGE's request to retain the UM 2003 deferral.

Q. Does this conclude your testimony?

A. Yes.