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August 11, 2022

Via Electronic Filing

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

RE: Docket No. UE 399 – In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision.

Attached for Rebuttal Testimony filing are the following:

UE 399 Staff Rebuttal Testimony Exhibits 1800-3000 Redacted Versions and Non- Confidential Exhibits, Cover Letter, Certificate of Service and Service List.

Please retrieve both versions from agency drive under Temporary Confidential Filings.

Confidential testimony, exhibits, and work papers will be available in the Huddle workspace after filing has been accepted.

/s/ Mark Brown
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UE 399 SERVICE LIST DATED 8-11-2022

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CERTIFICATE OF SERVICE

UE 399

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail (Huddle) pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 11th day of August, 2022 at Salem, Oregon

____

Mark Brown
Public Utility Commission
201 High Street SE Suite 100
Salem, Oregon 97301-3612
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CASE: UE 399
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1800

Rebuttal Testimony:
Overview, Public Comments,
Overall Rate of Return, Return on Equity, and
Changes Proposed to TAM and PCAM

August 11, 2022

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

A. My name is Matt Muldoon. My Position is Manager of Energy Rates and Finance of the Rates Finance and Audit (RFA) 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. Please see Exhibits Staff/100 for my opening testimony.

Q. What is the purpose of your testimony?

A. I introduce Staff Rebuttal Testimony adjustments and issues regarding the PacifiCorp (PAC, or Company) request for a general rate revision, docketed as Docket No. UE 399. Please refer to Exhibit No. Staff/1900, the testimony of John Fox for additional detail about component revenue, expense, and rate base components of Staff proposed adjustments.

In addition, I summarize public comments received by the Commission regarding this rate case, point to Staff testimony where these issues are examined and provide a count of the public comments that shared each concern.

I also address Cost of Capital components and overall Rate of Return (ROR), going into greater detail regarding Return on Common Equity (ROE), and Capital Structure.

In addition, please also note that I adopt **Staff Exhibit 900, Moya Enright**, Opening Testimony, and continue discussion of proposed changes to

PacifiCorp's Transition Adjustment Mechanism (TAM) and Power Cost Adjustment Mechanism (PCAM) herein.

Q. Will other Staff witnesses submit testimony regarding the issues they reviewed?

A. Yes. Each Staff assigned to Docket No. UE 399 is submitting separate testimony on outstanding issues. In my testimony, I first introduce the Staff witnesses and their respective assignments and estimate the revenue requirement impact of Staff recommended adjustments to the Company's initial filing.

Q. How is your testimony organized?

A. My testimony is organized around the following issues as follows:

1. Revenue Requirement Impact by Outstanding Staff Topic 5
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Capital Asset Pricing Model (CAPM) – As Check on ROE Findings 46
Table 9 – CAPM Model Results 49
Conclusion Regarding ROE and Capital Structure 50
5. Proposed Changes to PCAM and TAM 53

Q. Please outline other supporting exhibits for this testimony?

A. My testimony is supported by the following exhibits:

1801 Framework for ROE Modeling .... Page:
Average Authorized ROEs for Electric Utilities 3
" " " for Vertically Integrated Electric Utilities 8
Average Authorized Equity Ratio for Electric Utilities.............................. 7
1802 Framework for ROE Modeling .... Page:
Moody's vs. S&P Credit Ratings 1
Peer Utility Screening 2
Value Line (VL) Dividends for Modeling Peers 3
Earnings per Share (EPS) for Modeling Peers 4
Earnings per Share (EPS) for Modeling Peers Hamada Equation............ 5
1803 Three Stage Discounted Cash Flow (DCF) ROE Models .... Page:
Model X with Perpetual Dividend Cash Flow 1
Model Y with Terminal Sale of Stock 2
1804 Three-Stage DCF Modeling Results 1
1805 Capital Asset Pricing Model (CAPM) 1
1806 Single Stage (Gordon Growth) DCF Model 1
1808 U.S Treasury (UST) Treasury Inflation-Protected Security (TIPS)
Implied Inflation Rates 1
1809 Financial News
1810 VL Covered Electric Utilities

1. REVENUE REQUIREMENT IMPACT BY OUTSTANDING STAFF TOPIC

Q. Please provide a list of the rate case topics that Staff reviewed and introduce the responsible Staff.

A. See Table 1 below:

TABLE 1 – STAFF REBUTTAL TESTIMONY TOPICS

STAFF ISSUE SUMMARY **Twelve Months Ended December 31, 2023** **PAC UE 399**

Testimony	Issue No.	Staff	Staff Adjustments	Revenue Requirement Effect ($000)
Non-NPC Related Price Change (excludes TAM)				**$86,429**
1800	1	Muldoon	Revenue Requirement by Staff Topic	$0
	2		Intro to Staff Rebuttal Testimony	$0
	3		Summary of Public Comments Received	$0
	4		Overall Rate of Return (ROR)	
			Capital Structure	($6,561)
			Return on Equity	($17,204)
	5		Proposed Changes to PCAM and TAM	$0
1900	1	Fox	Summary of Findings and Recommendations	$0
	2		Overall Revenue Requirement	$0
	3		Deferral Amortization	$0
	4		TAM-Related Rev. Sensitive Expense	($170)
	5		Capitation Adjustment	$0
	6		Interest Sync.	($1,494)
	7		Escalation	$119
	8		Land	($30)
2000	1	Anderson	Coal Depreciation and Exit Order Changes	$0
	2		Removing Coal from Rates	$0
2100	1	Bain	Schedule 41 Load Forecast	$0
	2		Utah DSM in 2020 Protocol	$0

Continued on Next Page

1 (Continued)

2200	1	Bolton	VRET Procurement Cap	$0
	2		Customer Supply Option	$0
	3		Energy and Capacity Credit	$0
	4		Subscriber Mismatch and Administrative Fees	$0
	5		Competitive Bidding Rules	$0
	6		Compliance with VRET Condition 7	$0
	7		Percentage-Based Facility Output	$0
	8		Unbundled RECs	$0
	9		Direct Access Eligibility	$0
	10		Utah Schedule 34 Consistency	$0
2300	1	Cohen	Wages & Salaries , Incentives, and Full Time Equivalents (FTE)	($2,416)
2600	1	Fjeldheim	Customer Accounts Expenses, Non Labor	($3,393)
	2		Uncollectable Expense	($2,114)
			Adjust uncollectable rate to 0.336%	($106)
	3		Legal Fees & Expenses	($253)
2500	1	Storm	Wildfire Mitigation and Vegetation Management Mechanisms (WWVM)	($3,699)
	2		Amortization of COVID-19 Deferrals, and Rate Spread	$0
	3		Pensions and Post-Retirement Medical Expense	($6,611)
	4		Multi-State Process (MSP)	$0
	5		Klamath Hydroelectric Settlement Agreement (KHSA) and KRRC	$0
	6		Energy Vision 2020 Projects	$0
2700	1	Jent	Advertising	($94)
	2		Current Medical / Health Insurance	$0
	3		Non-Medical Insurance & Risk	($3,224)
2800	1	Moore	Wildfire / Vegetation Management	($6,785)
2900	1	Peng	Depreciation Expense	($1,106)
3000	1	Rossow	Memberships & Subscriptions	($33)
	2		Meals, Entertainment, and Awards	($7)

Total Staff Adjustments **($55,180)**

Staff-Calculated Revenue Requirements Change (Base Rates): **$31,249**

2. INTRODUCTION TO OTHER STAFF REBUTTAL TESTIMONY

Q. What is the exhibit number, respective Staff witness, and topics of the various Staff rebuttal testimonies?

A. The Staff Rebuttal Testimony exhibit number, respective Staff witness, and topics are presented below:

In Exhibit 1900, John Fox, Senior Financial Analyst further summarizes Staff findings and recommendations, discusses overall revenue requirement in detail and addresses deferral amortization.

In Exhibit 2000, Rose Anderson, Senior Economist, discusses two remaining issues: coal depreciation and exit order changes, and removing coal from rates.

In Exhibit 2100, Dr. Ryan Bain, Ph.D., Senior Economist, analyzes load forecasts, Utah DSM in 2020 Protocol, and Utah Schedule 34.

In Exhibit 2200, Madison Bolton, Utility and Energy Analyst, considers PacifiCorp's proposed Voluntary Renewable Energy Tariff (VRET) procurement cap, customer supply option, energy and capacity credit, subscriber mismatch fee and administrative fee, competitive bidding rules, compliance with VRET Condition 7, percentage-based facility output, unbundled Renewable Energy Credits (REC), and direct access eligibility.

In Exhibit 2300, Heather Cohen, Senior Utility Analyst, reviews wages, salaries, incentives, and full-time equivalents (FTE).

In Exhibit 2400, Dr. Curtis Dlouhy, Ph.D., Senior Economist, analyzes the Company's marginal cost study, rate spread, and residential rate design. In addition he reviews Utah Schedule 34 and Demand Side Management (DSM), as well as Irrigation distribution peaks. Dr. Dlouhy also considers a paperless bill credit.

In Exhibit 2500, Steve Storm, Senior Economist, examines seven issues: wildfire mitigation and vegetation management mechanisms, amortization of Covid-19 deferrals and associated rate spread, pensions and post-retirement medical expenses, Multi-State Process (MSP), Klamath Hydroelectric Settlement Agreement (KHSA) and KRRC, as well as Energy Vision 2020 projects.

In Exhibit 2600, Brian Fjeldheim, Senior Financial Analyst, addresses customer accounts expenses NL, uncollectibleble accounts, and legal expenses and fees.

In Exhibit 2700, Julie Jent, Utility Analyst, examines PacifiCorp's advertising expenses, current medical and health insurance expenses, and the Company's insurance and risk.

In Exhibit 2800, Mitch Moore, Senior Economist, analyzes PacifiCorp's proposed test-year expenses for wildfire and vegetation management.

In Exhibit 2900, Ming Peng, Senior Economist, analyzes depreciation expense.

In Exhibit 3000, Paul Rossow, Utility Economist, reviews the Company's memberships and subscriptions, as well as meals, entertainment and awards.

KEY CONCERN A – RATE SHOCK

Q. Does Staff continue to be concerned about the aggregate rate increase impact of this general rate case, deferrals and power costs on PacifiCorp's Oregon utility customers?

A. Yes, particularly as inflation is outpacing Oregon wages.[1]

Q. Has the Commission been concerned about magnitude of rate impact in the past regarding PacifiCorp?

A. Yes. The Commission has long considered rate shock to be a relevant factor in rate design.[2] Specifically, in Order No. 01-787 in PacifiCorp General Rate Case Docket No. UE 116, the Commission adopted a threshold for a rate mitigation adjustment on page 52, concluding:

> "We do not find that it is in the public interest to impose greater than 15 percent price increases."

This order was issued some time ago, when the Company was moving to cost-based rates, but is relevant in that PacifiCorp selectively cites elements of the ring fencing around purchase of PacifiCorp by MidAmerican Energy Holdings Company division of Berkshire Hathaway, Inc. from Scottish Power.[3]

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1 See Exhibit Staff/1808 Muldoon/17, 41, 45, 60, 86 and 102 for the inflation customers are experiencing.

2 *In the Matter* of *Portland General Electric*, Docket No. UE 115, Order No. 01-988 (November 20, 2001).

3 See the NBC News story of May 24, 2005, "Buffett buys PacifiCorp for $5.1 billion cash" at https://www.nbcnews.com/id/wbna7962826.

KEY CONCERN B – FINANCIAL RISK OF PACIFICORP

Q. Does Staff still think that PacifiCorp is grossly overstating the financing challenges faced by PacifiCorp?

A. Yes. PacifiCorp's testimony is full of internal contradictions. On the one hand, PacifiCorp's testimony says that the Company is not financially stressed. On the other hand, PacifiCorp's testimony suggests that most any investor owned utility in the U.S. that had investment grade credit ratings would be a reasonable peer of PacifiCorp for ROE modeling.[4]

Q. The Company continues to state in its Reply Testimony that, "… interest rates and utility share prices are inversely correlated … an increase in interest rates will result in a decline in the share price of utilities."[5] Does Staff agree that interest rates are currently the sole driver for utility stock prices?

A. No. This testimony will definitively show that PacifiCorp is paying attention to only one driver of utility stock price changes, and ignoring other factors that actually have caused utility stock prices to outperform the S&P 500 including an investor "Flight to Safety".[6]

Q. How have shares of U.S. IOUs in the S&P 500 index fared compared to the returns for the index as a whole since Russia invaded Ukraine?

A. U.S. IOU Stocks in the S&P 500 Index outperformed the S&P 500 as a whole.[7]

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4 See OAC/1400 Bulkley/47-48.
5 See PAC/300 Bulkley/21 at lines 3-5.
6 See Staff/1808 Muldoon/4, 14, 49, 54, 63, 71, 78 and 104.
7 See Staff/1808 Muldoon/4, 14, 49, 54, 63, 71, 78 and 104.

Q. Again, how much money is Mr. Buffet talking about keeping available is cash and cash equivalents at Berkshire Hathaway, Inc. (BRK)?

A. The amount fluctuates but has been over $100,000,000,000 dollars.[8]

Q. PacifiCorp's Reply Testimony states that the Company cannot readily access BRK liquidity. Is the Company's testimony plausible given the above context?

A. No.

Q. In the past two years after the Commission issued Order No. 20-473 in PacifiCorp's last general rate case, in Docket No. UE 374, did S&P or Moody's put PacifiCorp on credit watch, or lower the Company's credit ratings?

A. No.

Q. In its discussion of ring fencing conditions around BRK's purchase of PacifiCorp, has the Company or Mr. Gorman discussed the initial billion dollar financial guarantee BRK made, how that impacted PacifiCorp's credit ratings, and the lingering halo effect on PacifiCorp's ratings from being in the BRK family of companies – even after BRK removed the language from its annual reporting to the Securities and Exchange Commission.

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[8] See Exhibit Staff/109 Muldoon/3 and 67 for a sense of the magnitude of BRK cash reserves. Also See Exhibit Staff/1808 Muldoon 11, 98, and 110.

A. No. Omission of that halo effect causes PacifiCorp and Mr. Gorman to overstate the required equity layer in capital structure required for PacifiCorp to retain its current credit ratings.

Q. What is the usual credit rating agency discussion of the impact of parent holding companies on subordinate utility division ratings?

A. Usually the discussion is on the leakage of the impacts of excess debt at the holding company level, impairing the ratings of the regulated utility. Against that backdrop, PacifiCorp seems to think it reasonable to ask the Commission to ignore excess liquidity at BRK and the impact that has on the credit ratings of PacifiCorp. Staff would suggest rather that if some Commission jurisdictional utility credit ratings are dragged down by excessive debt at the holding company level, then the Commission should also consider the halo effect on credit ratings from the combination of tremendous excess liquidity at BRK and Mr. Buffet's statement cited in my opening testimony that Berkshire Companies would always, in all financial conditions, be able to pay their bills.

Q. How does Staff recommend the Commission approach back and forth criticisms of Cost of Capital Testimony between the Company, Staff and Mr. Gorman on behalf of AWEC and CUB?

A. Staff recommends the Commission consider the referent information and evidence provided by each party, and also perform a simple test of switching the actors in any given narrative to test the reasonableness of a given position.

Q. Can you give examples of what you mean by switching actors?

A. Yes. First consider Cascade Natural Gas were it purchased by BRK. Instead of having its credit ratings dragged down by excessive corporate debt at the parental holding company level, Cascade Natural Gas would gain a halo effect from excessive liquidity at the holding company level. That simple test of switching actors tests the appropriateness of ignoring excess debt or liquidity at the holding company level.

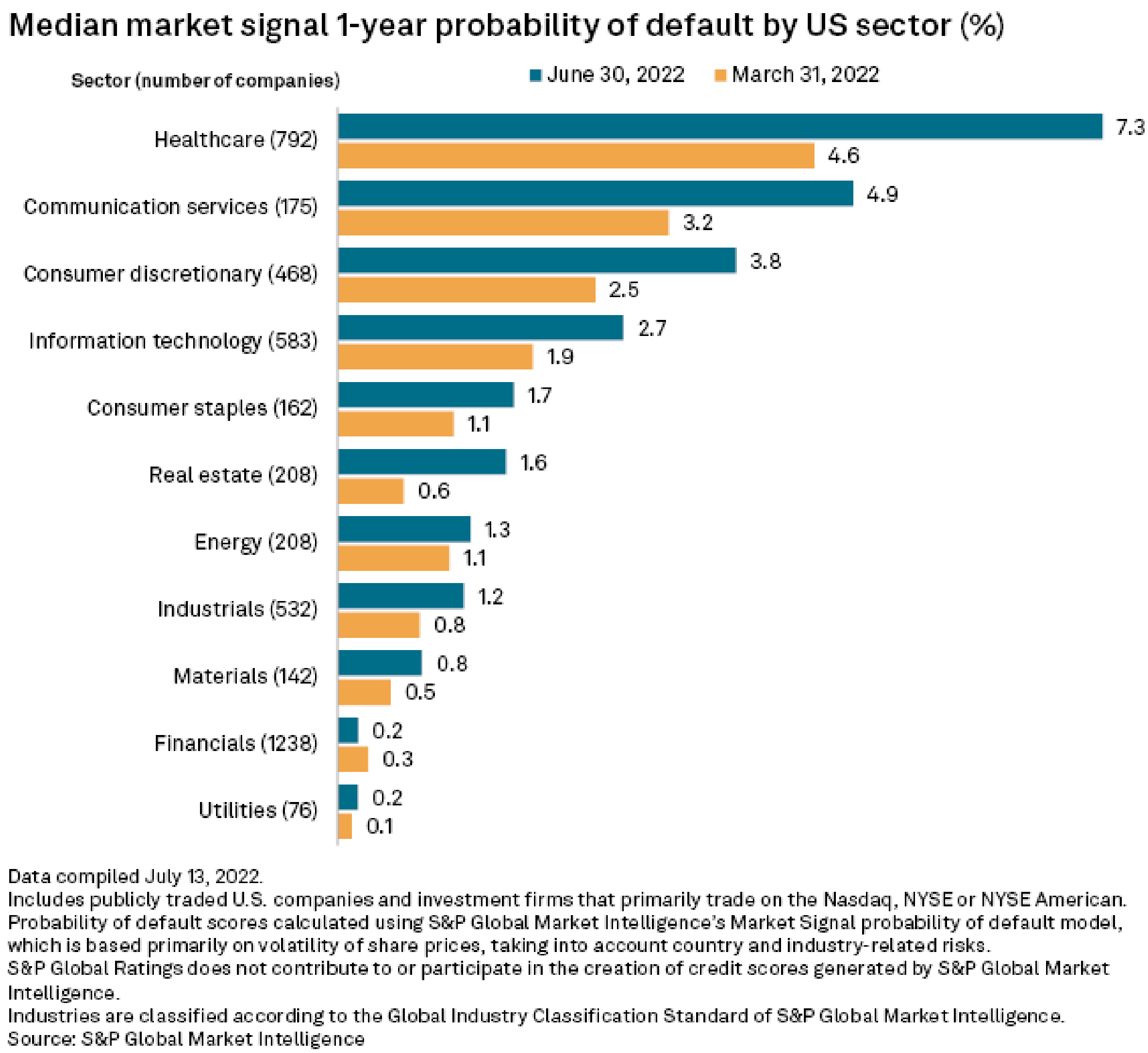
Q. In the above statement, is PacifiCorp both saying that the Company is more risky than peers but that most any electric utility with investment grade bond ratings would be an appropriate peer to consider for the Company?

A. Yes. While the Company also suggests in PAC/1400 Bulkley/48, 49 that peers need not be heavily regulated electric utilities, and in PAC/1400 Bulkley/52 that merger and acquisition activity need not concern an investor looking for peers most like PacifiCorp, another key exclusion method of PacifiCorp is elimination of utilities with adverse regulatory outcomes. While these and a variety of other PacifiCorp positions are all extreme suggestions unlikely to have resonance with investors with money at risk, the investment grade screen is truly amazing.

Q. Please clarify just what PacifiCorp is saying.

A. As shown in Figure 1 below, Investor Owned Utilities (IOU) are the least likely sector of the U.S. Economy to have a default in the near term. A simple translation is that any utility would do as a peer for PacifiCorp, regardless of whether its financial risk closely parallels PacifiCorp's.

FIGURE 1– Near Term Probability of Default of US IOUs[9]



Q. Does PacifiCorp even go on further to conclude that PacifiCorp has a "higher overall business risk than (Staff's) proxy group …"?

A. Yes. See Exhibit PAC/1400, Bulkley/74.

[9] See "Default Risk Rises across Most US Sectors in Q2" reproduced at Staff/1808 Muldoon/98 for easy access.

Q. Does PacifiCorp suggest that any agreement with the Company should mean that one should always agree with PacifiCorp and to do otherwise would be unreasonable?

A. Yes. See Exhibit PAC/1400, Bulkley/85.

Q. To be clear do Staff and Mr. Gorman find PacifiCorp's work on ROE reasonable?

A. No.

Q. PacifiCorp states that the stand-alone principle of ratemaking requires the Commission to ignore everything it knows about the parent company, BRK, is that accurate?

A. No. Rather PacifiCorp is to be evaluated like other IOUs. The Commission should of course be interested in how the parent influences PacifiCorp's likelihood of default on its bonds, on its credit ratings and how it flows cash into and out of PacifiCorp. Once again PacifiCorp asks the Commission to ignore the elephant in the room. That is another reason why PacifiCorp's contradictory testimony on ROE is worth the Commission's attention.

Q. Does this conclude your Introduction?

A. Yes.

3. SUMMARY OF PUBLIC COMMENTS RECEIVED

Q. Please summarize the public comments received to date in this rate case.

A. In this docket, the OPUC has received over 200 public comments.

TABLE 1

For Increase	Against Increase	Form Comments	Total Comments
3	204	151	207

Q. What is the range of perspectives shared by commenters?

A. Separate from the 151 identical emails, there are 53 other negative comments.

Q. Is there a common theme to the majority of comments received?

A. Yes. Docket No. UE 399's public comments generally reflect opposition to a rate increase except for three comments that support an increase. The overall sentiment from the public comments is that now is not an appropriate time for a rate increase of this size, especially in light of current events including inflation.

Q. Please explain the reasoning behind the inclusion of public comments in Staff's testimony.

A. Consistent with the Commission's Internal Operating Guidelines as addressed in Order 20-065 in Docket No. UM 2055, to provide more transparency about the public comments in contested cases, public comments received are now made part of the Staff's Opening Testimony.

This is the last round of testimony in which Staff may address public comments. However, comments received before the scheduled hearing date of September 8, 2022, will be posted with earlier public comments received.

Presenting comments at a Commission Informational Hearing or through the Commission's website does not subject the commenting person to cross examination at the upcoming hearing. Any party, though, may respond to Staff's summary of the public comments or the comments themselves in evidentiary testimony.

Q. Does Staff Rebuttal Testimony address comments received?

A. Yes.

4. OVERALL RATE OF RETURN (ROR)

Q. Did you prepare tables showing PacifiCorp's current Commission authorized, Company proposed and Staff calculated RORs?

A. Yes. The following three tables provide that information.

TABLE 2

PAC Current OPUC Authorized (UE 374 Order Nos. 20-473)			PAC
Component	**Percent of Total**	**Stipulated or Implied Cost**	**Weighted Average**
Long Term Debt	49.99%	4.774%	2.387%
Preferred Stock	0.01%	6.75%	0.001%
Common Stock	50.00%	9.50%	4.750%
	100.00%		**7.137%**

TABLE 3

PAC Requested – UE 399		PAC Reply Testimony		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long Term Debt	**47.74%**	**4.717%**	2.252%	**0.236%**
Preferred Stock	0.01%	**6.75%**	0.001%	
Common Stock	**52.25%**	**9.80%**	5.121%	
	100.00%		**7.373%**	

TABLE 4

Staff Proposed – UE 399		Staff Rebuttal Testimony		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long Term Debt	**49.99%**	**4.717%**	2.358%	**-0.178%**
Preferred Stock	0.01%	**6.75%**	0.001%	
Common Stock	**50.00%**	**9.20%**	4.600%	
	100.00%		**6.959%**	

Note: Based on a change in forward market conditions due to high inflation exacerbated by a war in Eastern Europe, and projected Federal Reserves (Fed) interest rate actions to control inflation, Staff and the Company recommend a higher cost of Long-Term Debt than did PacifiCorp in its initial testimony.

Capital Structure

Q. After reviewing the Company's Reply Testimony and Mr. Gorman's Opening Testimony, has Staff changed its recommendations regarding capital structure?

A. No. Staff believes the Company and Mr. Gorman have not addressed the elephant or BRK in the room. Neither addressed the halo effect of having substantial excess liquidity at the BRK holding company level. Again, normally the Commission hears about the negative leakage of excessive debt at the holding company level impacting the credit ratings of subordinate regulated utilities.

Neither the Company nor Mr. Gorman discuss the history of PacifiCorp's credit ratings and the impact of guarantees by BRK of PacifiCorp's financial health. Staff believes this is an oversight on Mr. Gorman's part, and understands that there is a draw to crunching numbers before considering the context and history of the relationship between BRK and PacifiCorp.

Staff is not as generous in its assessment of PacifiCorp's discussion of credit ratings and ring fencing, which selectively omits a discussion of guarantees that were part of the benefits MidAmerican Energy Holdings Company (now Berkshire Energy) offered as reason that regulators could trust the effectiveness of ring-fencing conditions imposed by the Oregon Commission and other state utility regulators. Staff suggests that the Commission's own review of the ring-fencing conditions in coordination with financial guarantees leads to a much different context than the picture

PacifiCorp is painting.

Q. Is there Commission precedent for Staff's recommended 50 percent equity layer capital structure?

A. Yes. In Order No. 20-473 at 24: Commission adopted a notional 50 percent equity capital structure – "We consider all components to the company's cost of capital that will result in a fair and reasonable rate of return, 'to strike a balance between the interests of ratepayers and the interests of investors.'"

Q. In Opening Testimony you indicated PacifiCorp thinks Portland General Electric has an easier time in maintaining credit ratings than PacifiCorp, do you still disagree?

A. Yes. Staff disagrees with PacifiCorp for many reasons including the following:

1. PacifiCorp is a wholly owned subsidiary of BRK. It does not need to maintain a regular and growing quarterly dividend to satisfy investors when the Company has opportunities for capital spending for utility purposes.
2. Actual capital structure for PacifiCorp is at the Company and its parent BRK's discretion. It is not simply driven by financial market conditions.
3. BRK seeks investment opportunities that exceed the meager return it receives for holding short-term U.S. Treasuries (UST). PacifiCorp's authorized rate of return is about double that earned on BRK's UST. PacifiCorp's authorized return on equity is an even greater magnitude larger than BRK's UST.

Q. Staff points to cash reserves (UST) owned by PacifiCorp's parent company, BRK as proof PacifiCorp is at least somewhat insulated from concerns about inflation, credit worthiness and certain requirements of other investor owned utilities. How does that cash balance ensure that insulation considering how many businesses are owned by BRK?

A. BRK cash reserved are over twice the entire $50 Billion market capitalization of PacifiCorp. Those holdings exceed 15 percent of the market cap of all of BRK combined. With these reserves BRK can operate for an extended period of time, even if capital markets were entirely frozen or non-functional such in a depression.

PacifiCorp also does not need to float stock in these times as a wholly owned subsidiary. Further PacifiCorp can go for some time paying no dividends as needed or reflective of capital spending opportunities, sharply contrasting with most IOUs which must have a steady and growing dividend to avoid being dropped by investors.

Q. Is the Company's testimony provided in Exhibit PAC/200 Kobliha sufficient justification for PacifiCorp's proposed capital structure?

A. No. PacifiCorp's substantial control over its capital structure and its capital spending opportunities – in part because it had built so many coal-fired generation resources – does not justify preferred treatment for the Company.

Q. Again, what are the currently authorized capital structures of the other five Commission jurisdictional energy IOUs?

A. All five are within 10 basis points (bps) of a 50 percent Equity and 50 percent

Long-Term Debt Capital Structure. See below for their equity layers:[10]

AVA	CNG	IPC	NWN	PGE
50.0 %	50.0 %	49.9 %	50.0 %	50.0 %

Q. Does Commission authority for a jurisdictional utility to self-build and grow authorized rate base mean it must have a higher equity layer in capital structure.

A. No.

Q. Are interest rates at all-time highs?

A. No. Despite Federal Reserve intent to raise interest rates, currently interest rates are closer to all-time lows. Debt is still relatively cheap compared to equity at this time.

Q. If the Commission in this case were to repeat its previous PacifiCorp decision to adopt a 50/50 debt equity structure, would that force PacifiCorp to take action to adjust its capital structure?

A. No. The Commission sets a capital structure for purposes of setting rates. PacifiCorp and BRK are free to have whatever capital structure they want for operating and business purposes. The fact that PacifiCorp and BRK decide to have more equity in PacifiCorp's capital structure is not market forced, as discussed earlier, as PacifiCorp equity is not a publicly-traded company.

10 Avista Corp. (AVA); Cascade Natural Gas (CNG); Idaho Power Company (IPC); Northwest Natural Gas (NWN) and Portland General Electric (PGE).

Return on Equity (ROE)

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

A. Staff updated its modeling and based on updated results recommends a **point ROE** of **9.2 percent** within a range of reasonable ROEs of 8.99 percent to 9.33 percent derived from Staff's two separate Three-Stage Discounted-Cash-Flow (DCF) models. The Commission has traditionally relied on the Three-Stage DCF models for its authorized ROE decisions.

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

A. Yes. Staff updated and employed two 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 updated Gordon Growth Model generated a mean ROE of 8.9 percent using Staff's peer electric utilities and 8.9 percent with the Company's peer electric utilities.

The updated CAPM generated a mean ROE of 9.5 percent using Staff's peer electric utilities and 9.5 percent as well with the Company's peer electric utilities.

Based on these conflicting checks, one pointing to top of range and one pointing to bottom 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 at the midpoint of modeling results reflective of the above checks on reasonableness. Further, when considering large rate increase impacts on Oregon utility customers, and the strong financial health of the utility, it is reasonable for the Commission to consider authorizing an ROE below the top of range of reasonable ROEs.

Q. Does your recommended ROE meet appropriate standards?

A. Yes. The 9.2 percent ROE Staff continues to recommend is appropriate for overall rates that are reflective of forward looking conditions in conjunction with Staff's adjustments and meets the *Hope* and *Bluefield* standards, as well as the requirements of Oregon Revised Statute (ORS) 756.040.[11] 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 ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[12]

Q. What claims does PacifiCorp make regarding Hope and Bluefield in the Company's reply testimony?

A. PacifiCorp suggests that absent extraordinary extra Commission consideration given the Company's self-build capital spending opportunities, Hope and

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[11] *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).

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

Bluefield would not be met because PacifiCorp would be compared with utilities with less risk, and that the overall outcome for Rate of Return would be unreasonable.

Q. Does Staff agree that PacifiCorp's novel arguments regarding Hope and Bluefield have merit?

A. Staff does not. Staff's recommendations provide for reasonable return for PacifiCorp based on its relative risk in comparison to peer utilities employed for modeling an appropriate ROE for PacifiCorp. PacifiCorp and Staff disagree on what peer electric utilities best represent PacifiCorp, on how relatively risky PacifiCorp is compared to appropriate peer utilities, and even about what ring fencing and guarantees can inform this general rate case.

Q. When PacifiCorp says, "Mr. Muldoon effectively ignores the Hope decision …" does this imply PacifiCorp does not understand the Hope and Bluefield decisions?[13]

A. I am not an attorney, but as a financial analyst, this looks to be gross misunderstanding on PacifiCorp's part, and the meaning of the case can be further addressed in Staff's brief.

PEER SCREEN

Q. PacifiCorp in its Reply Testimony suggests that Staff's screening and inputs are outdated or stale. Has this been addressed?

A. Yes, Staff updated its screening and other modeling inputs.

[13] See PAC/1400 Bulkley/44.

Q. How did you select comparable companies (peers) to estimate PacifiCorp's ROE in your updated modeling?

A. Staff updated its screening and used companies that met the following criteria as peer utilities to the regulated electric utility activities of PacifiCorp:

1. Covered by VL as an electric utility;
2. Forecasted by VL to have positive dividend growth;
3. LT Issuer Credit Rating from A1 to Baa2 inclusive from Moody's and from AA- to BBB+ inclusive from S&P;
4. No decline in annual dividend in last five years based on VL;
5. Has heavily regulated electric utility revenue;
6. Has LT Debt from 45 percent to 55 percent inclusive in VL Capital Structure; and,
7. Has no recent merger and acquisition activity.

Q. What peer groups of electric utilities did Staff and Company ROE modeling primarily depend on, and were there similarities?

A. The Company and Staff recommended regulated electric utility peer groups both drew from pertinent electric utilities covered by VL. In Staff Exhibit 102, Page 2, Staff flags electric utilities not selected due to merger activity as it shows how each element of its screening was applied. Table 5 shows a fair amount of overlap between PacifiCorp's and Staff's peer groups.

Q. Did Staff's peer group change when it reapplied its screening methods.

A. Yes. When Staff reapplied its Screening as it updated its modeling, this added Black Hills and removed Duke from Staff's peer utility group.

Q. Did the Company apply some different criteria?

A. Yes. PacifiCorp emphasized thermal generation fuel mix, which Staff continues to see as largely a distraction. There was overlap between PacifiCorp's and Staff's screening criteria. However, The Company in its Reply Testimony had a large number of criticisms of Staff's well vetted and consistent screening methods.

Q. Why does Staff consider generation fuel mix as largely a distraction?

A. PacifiCorp focuses on coal-fired generation but selects peer utilities that rely on substantial nuclear generation.[14] For example, one of PacifiCorp's peer utilities is Southern Company (New York Stock Exchange (NYSE) Ticker (SO), which has 2 nuclear units under construction.[15] SO's share of the nuclear projects is 45.7 percent or $10.4B of project.[16] PacifiCorp's own nuclear exposure does not seem to be consistent with PacifiCorp's ROE modeling emphasis on generation fuel mix.[17]

A comparison of the peer groups used by Staff and PacifiCorp are set forth in Table 5. Staff's updated screening excluded eleven of the companies used by PacifiCorp based on its screening criteria described above. PacifiCorp excludes five of the companies used by Staff. Four companies were relied upon by both Staff and PacifiCorp.

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14 See Exhibit PACIFICORP /1400 Bulkley/58 for discussion and PAC/1402 Bulkley/2 for PacifiCorp's Proxy Group.

15 See Exhibit Staff/1808 Muldoon/70.

16 See S&P Global Market Intelligence article, "NRC Approves Southern's Vogtle Unit 3 for Nuclear Fuel Load, Operation" published Aug. 3, 2022 and accessible on Staff/1808 Muldoon/70.

17 See Value Line, Southern Company for more information on SO's two nuclear units being added to its Vogtle Station in Exhibit Staff/1809 Muldoon/37.

TABLE 5[18]

Abbreviated Utility	UE 399 PAC	UE 399 Staff
Allete	Yes	No
Alliant	Yes	Yes
Ameren	Yes	Yes
AEP	Yes	No
Avista	Yes	No
Black Hills	No	Yes
CMS	Yes	No
Consol Ed	No	Yes
Duke	Yes	No
Entergy	Yes	No
Evergy	Yes	Yes
Eversource	No	Yes
IDACORP	Yes	No
NextEra	Yes	No
NorthWestern	Yes	No
Otter Tail	Yes	No
PGE	Yes	Yes
Pinnacle	No	Yes
Southern	Yes	No
WEC	No	Yes
Xcel	Yes	No
No. of Peers:	16	**9**

Q. PacifiCorp notes that Mr. Gorman uses the Company's peer group, is this significant?

A. Mr. Gorman's use of PacifiCorp's peer utility group cannot be considered an endorsement. In Staff's experience over the past decade, Mr. Gorman always has started with the utility's peer group, keeping the focus on his modeling rather than peer screening. However, this is a significant factor when considering Mr. Gorman's results. Use of the Company's peer screen in lieu of

[18] See Exhibit Staff 1802, Muldoon/2 for the full peer screening table.

Staff's boosts Staff's Model X by 16 bps and Staff's Model Y by 23 bps over the use of Staff's peer group, which was published simultaneously with Mr. Gorman's Opening Testimony. That could push the upper range of Mr. Gorman's Modeling results up to 23 basis points over what would be expected using Staff's long vetted screening methodology and Staff's resultant peer group.

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.

TABLE 6 – RESULTS OF STAFF'S 3-STAGE DCF MODELING[19]

Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by :				12.5	bps
	8.99%	to	9.33%	ROE	
Staff Point ROE Recommendation:	Midpoint	9.2%	ROE	Testimony	

CAPM and Single Stage DCF point to top and bottom respectively of Staff's Three Stage DCF Modeling Results

Supporting Exhibit Staff/1804 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 PacifiCorp's peer electric utility group.

Q. Are there other key drivers that cause the Company's modeling to generate different results than utilizing Staff's modeling?

A. Yes. In its Three-Stage DCF, PacifiCorp relies on a 5.49 percent long-term third-stage growth rate. This caused the Company to have to reach back to the

[19] See Exhibit Staff/1804, Muldoon/1 for the results of Staff three-stage DCF modeling.

1920's to pull in periods of higher growth than have been experienced by most investors in their lifetimes.

Q. Has PacifiCorp remedied this error of judgement?

A. No. PacifiCorp has not taken the opportunity to repair its modeling based on feedback in opening testimony from Mr. Gorman and Staff.

Q. Please provide another example of an extreme input that PacifiCorp has not labeled as such.

A. In its CAPM modeling PacifiCorp Reply Testimony continues to overstate its market risk premium estimate.

Example 1 – NOT a Staff Recommendation:

PAC	1.87%	Rf Rate as shown in Exhibit PAC/307 Buckley/1 -- Top Current Table
Opening	12.63%	Mkt Return as shown in Exhibit PAC/408 Buckley/1 - Top Current Table
Testimony	10.76%	PAC Mkt Risk Premium (MRP)
Staff	3.010%	R_f as August 2, 2022 30 Yr UST Yields W! Bonds & Rates (wsj.com)
	10.70%	30 Year S&P 500
	7.69%	Staff Mkt Risk Premium MRP)

Note that PacifiCorp does not identify its "extreme" market risk premiums as such.

PacifiCorp has not corrected for excessive inputs in its Reply Testimony and has not labeled these inputs as outlier values. Instead, PacifiCorp has offered unreasonable adjustments to Staff's and Mr. Gorman's models, mislabeling them as "reasonable adjustments".[20] Similarly PacifiCorp mischaracterizes Staff's Opening Testimony as "relying solely on the results of … Multi-Stage Discounted Cash Flow (DCF) analysis", which as the Commission can readily see is inaccurate.[21]

20 See PAC/1400 Bulkley/3 @21.
21 See PAC/1400 Bulkley/3 @16-17.

	Screen #	Abbreviated Utility	UE 399 PAC	UE 399 Staff	Ticker	VL Q2 2022 Beta	ROE w VL Beta CAPM	Screen #		ROE w VL Beta CAPM
1	1	Allete	Yes	No	ALE	0.90	9.93%	1	1	12.69%
2	2	Alliant	Yes	Yes	LNT	0.80	9.16%	2	2	11.62%
3	3	Ameren	Yes	Yes	AEE	0.80	9.16%	3	3	11.62%
4	4	AEP	Yes	No	AEP	0.75	8.78%	4	4	11.08%
5	6	Avista	Yes	No	AVA	0.90	9.93%	6	5	12.69%
6	7	Black Hills	No	Yes	BKH	0.95	10.32%	7	6	13.23%
7	9	CMS	Yes	No	CMS	0.75	8.78%	9	7	11.08%
8	10	Consol Ed	No	Yes	ED	0.75	8.78%	10	8	11.08%
11	13	Duke	Yes	No	DUK	0.85	9.55%	13	11	12.16%
12	16	Entergy	Yes	No	ETR	0.90	9.93%	16	12	12.69%
13	17	Evergy	Yes	Yes	EVERG	0.90	9.93%	17	13	12.69%
14	18	Eversource	No	Yes	ES	0.90	9.93%	18	14	12.69%
16	24	IDACORP	Yes	No	IDA	0.80	9.16%	24	16	11.62%
17	26	NextEra	Yes	No	NEE	0.90	9.93%	26	17	12.69%
18	27	NorthWestern	Yes	No	NWE	0.95	10.32%	27	18	13.23%
20	29	Otter Tail	Yes	No	OTTR	0.85	9.55%	29	20	12.16%
21	31	PGE	Yes	Yes	POR	0.85	9.55%	31	21	12.16%
22	32	Pinnacle	No	Yes	PNW	0.90	9.93%	32	22	12.69%
25	38	Southern	Yes	No	SO	0.90	9.93%	38	25	12.69%
26	40	WEC	No	Yes	WEC	0.80	9.16%	40	26	11.62%
27	42	Xcel	Yes	No	XEL	0.80	9.16%	42	27	11.62%
		No. of Peers:	16	9			VL Betas			VL Betas
				Company Screen		Mean	9.5%	ROE		12.2%
				Staff Screen		Mean	9.5%	ROE		12.2%

Points to Upper Half of Staff's 3-Stage DCF Results

Above to the right is an updated example of how PacifiCorp generates ROE modeling results above 12 percent.

Q. PacifiCorp/300 Bulkley/3 at lines 20-21 indicates the Company finds a reasonable range of ROEs from 9.9 to 10.75 percent, with a point request by the Company of 9.8 ROE below the low end of this range. Why is that not a reasonable recommendation?

A. If you eliminate unreasonable modeling inputs, select only peer electric utilities most like PacifiCorp using Staff's standard screening methods, and eliminate the Company's Risk Premium Modeling, you arrive at result equal to Staff's ROE recommendations.[22]

[22] Exhibits Staff/1802 – /1806 show how Staff's recommendations are generated.

According to Regulatory Research Associates (RRA), US Electric and Electric ROE Determinations in H1, 2022 Remain near All-Time Lows.[23] PacifiCorp's recommendations do not seem to have any correlation whatsoever to prevailing state commission decisions regarding authorized ROE in rate case decisions this year. According to RRA, and affiliate of S&P Global Market Intelligence, "The full-year averages in recent years are at the lowest levels ever witnessed in the industry." Yet PacifiCorp suggests that it should be authorized a 30 bps increase in ROE, contrary to the Industry trend downward.

Q. Is use of Value Line as the source of dividend information a flaw in Staff's modeling as suggested by PacifiCorp?[24]

A. No. The Commission has long used Value Line for this purpose.

Q. What does RRA say is the industry average ROE for vertically integrated electric utilities in cases decided in the first six months of 2022?

A. That was 9.47 percent, versus the 9.53 percent average posted in full year 2021.[25]

Q. Does PacifiCorp request an authorized ROE 6 bps lower than last authorized in Commission in Order No. 20-473 in the Company's last

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[23] See Exhibit Staff/1801.
[24] See PAC/1400 Bulkley/47.
[25] See Exhibit Staff/1801.

rate case, Docket No. UE 374, to track the fall in authorized ROEs nationally for vertically-integrated utilities as noted above?

A. No.

Q. Given that the Commission is usually a bit lower in its authorizations than some other state utility commissions, how does S&P Global Market Intelligence affiliate Regulatory Research Associates (RRA) rank the Oregon Commission?

A. RRA ranks it average. The Commission appears to rating agencies and their affiliates as neither excessively generous – nor excessively harsh. Effectively, these referent entities find the Commission practices in aggregate fair and reasonable, which would be consistent with the requirements of Hope and Bluefield.

LT GROWTH RATES - USED IN THIRD STAGE OF DCF MODELS[26][27]

Q. What long-term growth rates did you use in Staff's two three-stage DCF models?[28,29]

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

The first method uses the U.S. Congressional Budget Office's (CBO)

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26 See Exhibit Staff/1806, Muldoon1 for BEA historical GDP growth rates.

27 See Exhibit Staff/1807, Muldoon1 for TIPS implied long-run inflation rates.

28 Methods used here related to GDP-based growth rates are similar, if not identical to methods Staff has used in past proceedings. *See*, as an example, Staff's discussion of these methods and, to a limited extent, their conceptual underpinnings in Docket No. UE 233, Exhibit Staff/800, Storm/46 – 52. Growth rates relied upon by Staff are also shown in Exhibit Staff/1804, Muldoon/1

29 See three-stage DCF models X and Y in Exhibit Staff/1803.

4.0 percent nominal 20-year GDP growth rate estimate.

Staff's second Composite Growth Rate applies a 50 percent weight to the average annual growth rate resulting from estimates of long-term GDP by the U.S. Energy Information Administration (EIA), the U.S. Social Security Administration, PricewaterhouseCoopers estimate for long-run (10- to 30-years from now), and the CBO, with each receiving one-quarter of that 50 percent weight.[30] The remaining 50 percent is the average annual historical real GDP growth rate, established using regression analysis, for the period 1980 through 2021 to which we apply a TIPS implied inflation forecast.

Staff's third "Near Historical" Stage 3 annual growth rate, is the earlier described U.S. Bureau of Economic Analysis (BEA) derived projection which presumes the future will look much like the past. Table 7 below captures Staff's LT GDP growth rates with updated TIPS analysis and higher inflation.

[30] The EIA is the Energy Information Administration within the U.S. Department of Energy (DOE), OMB is the Office of Management and Budget, and CBO is the Congressional Budget Office. EIA and OMB's estimates are of nominal GDP. We applied to CBO's estimate of real GDP as an inflation rate for the relevant timeframe developed using the Treasury Inflation-Protected Securities method described by Staff in testimony in multiple recent general rate case proceedings.

TABLE 7
GROWTH RATES STAFF RELIED UPON

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)	2.10%	2.38%	4.53%	12.50%	0.57%	
PricewaterhouseCooper	2.40%	2.38%	4.84%	12.50%	0.60%	
Social Security Administration	2.00%	2.38%	4.43%	12.50%	0.55%	
Congressional Budget Office	1.60%	2.38%	4.02%	12.50%	0.50%	
BEA Nominal Historical,1980 Q1 – 2021 Q4	2.66%	2.38%	5.10%	50.0%	2.55%	
Composite				100%	4.78%	Composite
Congressional Budget Office Long-Term 20-Year Budget Outlook			4.00%	100.0%	4.00%	CBO
BEA Nominal Historical,1980 Q1 – 2021 Q4	2.66%	2.38%	5.10%	100.0%	5.10%	Near Historical
Though shown below for comparison purposes - Staff disagrees with the Company's third Stage Growth Rate						5.49%

Q. Did you integrate the higher TIPS based estimation of longer-run inflation into Staff's ROE modeling?

A. Yes. Staff utilized synthetic forward curve using UST Treasury Inflation Protected Securities (TIPS) break-even points. This reflects implied market-based inflationary expectations of 2.38 percent. Staff's recommendations are consistent with current market activity and Fed surveys indicating investor expectations of future inflation.[31]

Staff assumes for purposes of its three-stage DCF modeling that LDC utility growth is bounded by the growth of the U.S. economy, and more specifically impacted by challenges regarding U.S. population, workforce participation, and productivity in the long-run (20-year) modeling period.

Q. Does PacifiCorp make a faulty attempt to improve on Staff's TIPS inflation calculations?[32]

[31] See Staff/1808 Muldoon/115 for the Article in the Aug. 9, 2022 WSJ, "Americans Reduce Inflation Expectations".

[32] See PAC/1400 Bulkley/33.

A. Yes. While PacifiCorp's criticisms add nothing, Staff has updated its inflation estimation which increased in Staff's updated modeling to 2.38 percent.[33]

Q. Assume that future U.S. GDP growth would look like the growth experienced in the past 30 years. Would a ROE based on that assumption still fall within Staff's recommended range?

A. Yes. Staff extracted and ran regression on data from the U.S. Bureau of Economic Analysis (BEA) to generate the annual real historical GDP growth rate. Staff recommended range of ROEs includes values that presume GDP growth over the next 30 years would look like that of the past 30 years informed by other federal projections.

Q. How do your growth rates compare to the Company's?

A. Staff's 20-year GDP growth rate estimates of 4.0 percent from the U.S. Congressional Budget Office (CBO); 4.62 percent aggregated from the U.S. Energy Information Administration (EIA), Pricewaterhousecooper, the U.S. Social Security Administration, the CBO, and the U.S. Bureau of Economic Analysis (BEA) (Composite); and Staff's regression analysis of BEA historical data of 4.95 percent are much lower than the Company's proposed 5.49 percent. Staff's work is more consistent with referent data sources.

Q. How do your methods employed in this case differ from those utilized by Staff in recent general rate cases?

A. Staff's methods and modeling parallel those employed by Staff in recent electric utility general rate cases. Staff continues to look primarily to referent

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[33] See Staff/1802 Muldoon/4.

federal sources for long-term GDP growth rates which weight long-run population, workforce participation, and productivity higher than current financial market events and global events with shorter if not transitory effects. Nevertheless, Staff monitors current financial news and this testimony is informed by such.[34]

Q. Is the Staff DCF models the same models used in prior electric general rate cases?

A. Yes.

HAMADA EQUATION

Q. Your application of the Hamada Equation to un-lever peer utility capital structures and to re-lever at PacifiCorp's target capital structure increases required ROE. Why is this adjustment reasonable?

A. Staff employs the Hamada Equation to better compare companies with different capital structures driven by differing amounts of outstanding debt. As earlier discussed, Staff applied screening criteria already identify peers that have a very close capital structure to the Company. Use of the Hamada-adjusted results helps ensure that Staff has captured all material risk in our analysis because it captures additional risk associated with varying capital structure.

Within the confines of Staff's testimony, one can see the steps to un-lever and re-lever a peer company's capital structure as the equivalent of removing

[34] See Exhibit Staff/1808 for news that investors in electric utilities are seeing.

debt of peer companies with varying capital structures, and then adding enough debt back to equal the Company's balanced target capital structure in this general rate case.

Q. PacifiCorp is concerned with Staff's Hamada market risk premium. Is Staff's market risk premium based on solid referent thinking?

A. Yes. Staff relies on "Rethinking the Equity Risk Premium" by Laurence M. Siegel, Martin L Liebowitz et al. This is available on Amazon.com.

Q. Describe how you performed your analysis.

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

Q. Was your analysis consistent with a top supportable finding of 9.2 percent point ROE?

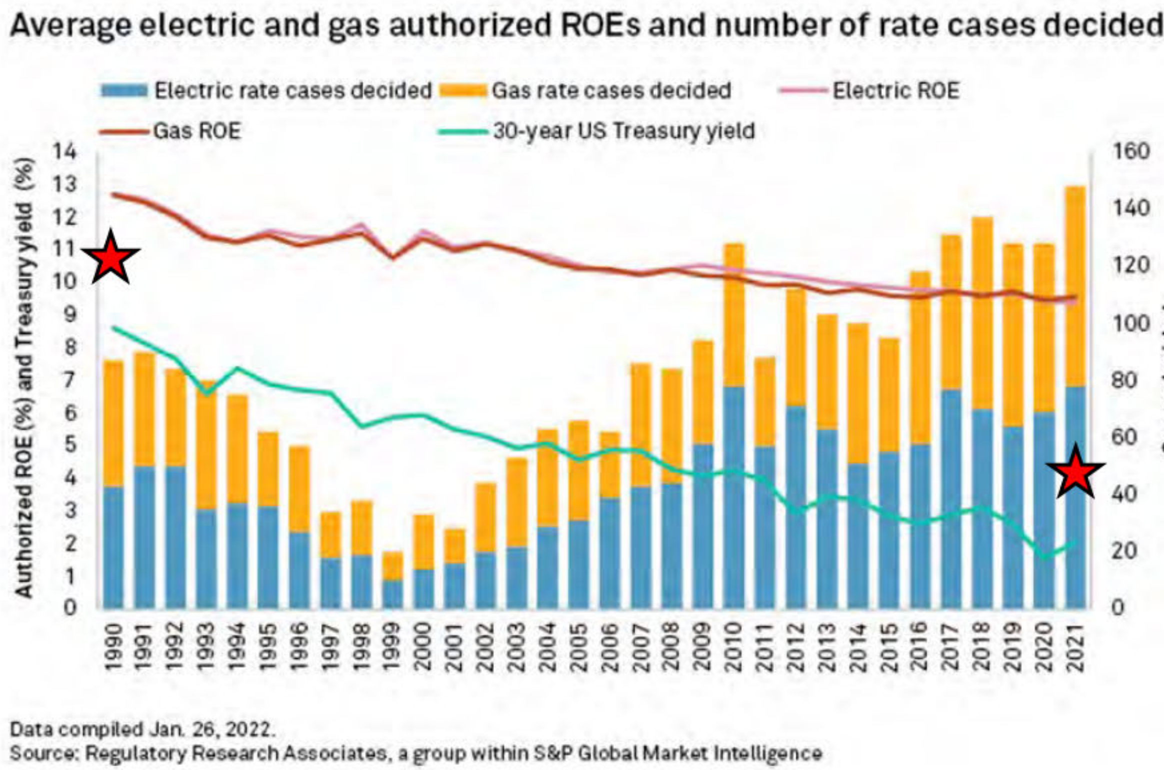
A. Yes.

BALANCED APPROACH TO ROE

Q. Are your results robust given uncertainty around COVID-19, high inflation, U.S. Federal Reserve (Fed) intent to raise interest rates, and a major war in Eastern Europe further disrupting global supply chains?

A. Yes. The downward glide path for ROE in Figure 2 below, is not linear and may fluctuate through these uncertainties, but long-run GDP growth rates are mostly determined by the long future U.S. working age population and its productivity.[35]

FIGURE 2 – Downward Glide Path of Utility ROES[36]



Q. What trend is Staff seeing?

A. Since 1990, according to Regulatory Research Associates (RRA), Electric and Electric Utility authorized ROEs have declined as the 30-year US Treasury (UST) has also declined. While the Fed now proposes to raise interest rates, to date it has increased short term rates by less than 100 basis points to date, leaving Treasury yields still close to all-time lows.

35 See Exhibit Staff/108, Muldoon/1, 20 for pertinent population growth rates.

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

Q. PacifiCorp is concerned that Staff is relying on an outdated understanding of Fed interest rate activity.[37] Is this accurate.[38]

A. No. Staff sees Fed actions up to the point at which it prepares testimony for publication. Fed guidance can vary from its actual decisions. For example note the more aggressive Fed actions in the last two decisions in comparison with earlier guidance of 50 bps changes.

FIGURE 3 – Recent Fed Interest Rate Decisions[39]

2015 Q4 Federal Funds Rate Target lifted by 25 bps to (0.25 to 0.50)%
2016 Q4 Federal Funds Rate Target lifted by 25 bps to(0.50 to 0.75)%
2017 Q1 Federal Funds Rate Target lifted by 25 bps to (0.75 to 1.00)%
2017 Q2 Federal Funds Rate Target lifted by 25 bps to (1.00 to 1.25)%
2017 Q4 Federal Funds Rate Target lifted by 25 bps to (1.25 to 1.50)%
2018 Q1 Federal Funds Rate Target lifted by 25 bps to (1.50 to 1.75)%
2018 Q2 Federal Funds Rate Target lifted by 25 bps to (1.75 to 2.00)%
2018 Q3 Federal Funds Rate Target lifted by 25 bps to (2.00 to 2.25)%
2018 Q4 Federal Funds Rate Target lifted by 25 bps to (2.25 to 2.50)%

2019 Q3 Federal Funds Rate Target **lowered** by 25 bps to (2.00 to 2.25)%
2019 Q3 Federal Funds Rate Target **lowered** by 25 bps to (1.75 to 2.00)%
2019 Q4 Federal Funds Rate Target **lowered** by 25 bps to (1.50 to 1.75)%
2020 Q1 Federal Funds Rate Target **lowered** by **50** bps to (100 to 1.25)%
2020 Q1 Federal Funds Rate Target **lowered** by **100** bps to (0 to 0.25)%
2022 Q1 Federal Funds Rate Target lifted by 25 bps to (0.25 to 0.50)%
2022 Q2 Federal Funds Rate Target lifted by **50** bps to (0.75 to 1.00)%
2022 Q2 Federal Funds Rate Target lifted by **75** bps to (1.50 to 1.75)%
2022 Q3 Federal Funds Rate Target lifted by **75** bps to (2.25 to 2.50)%

Neither Staff nor the Company have perfect foresight on fixed income markets. The usual bit of humor is that this explains why we are working for a living. Moody's perspective is that the Fed may be aggressive now so as to allow for a pause or slowdown in increases later this year and potential rate reductions depending on U.S. economic performance next year.[40] But the Fed has indicated that it will respond to actual market data, which is not yet known.

Q. How does Jason Lusk, professor of economics at Purdue University characterize current market relationships?

A. Professor Lusk says, "It is not a single simple story".[41]

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37 See PAC/1400 Bulkley/28.

38 See PAC/1400 Bulkley/22 for PacifiCorp's selective omission of utility stock price drivers.

39 Source WSJ as of Jul. 28, 2022

40 See Staff 1808 Muldoon/1, 7, 19, 22, 27, 29, 32, 38, 61, 67, 84, and 94 for articles that better explain current market direction and uncertainty,

41 See Staff/1808 Muldoon/93.

Q. Does PacifiCorp mischaracterize Mr. Gorman's basis statement that indicated that while interest rates have risen recently, interest rates are still low and not expected to increase to historical heights in the next few years?

A. Yes.[42]

Q. PacifiCorp emphasizes again in its Reply Testimony that, "Since utility stocks are inversely correlated with the yields on long-term government bonds, rising interest rates are projected to result in declining utility stock prices …"? Does Staff find that this explanation provided in PAC/1400 Bulkley/8 paragraph 6 is fully explanatory of recent utility stock price movement?

A. No. Recent utility stock price movement is more complex than as explained by PacifiCorp. Moody's and S&P Global Market Intelligence explain the other drivers which currently are overwhelming the single tendency that PacifiCorp highlights. The variety of other factors including the War in Ukraine, resultant further disruption of global energy and other prices, and concerns about recession have led to an investor flight to safety that looks for dependable domestic U.S. cash flows with little exposure to international market disruptions. It is telling that PacifiCorp again leaves out the elephant in the room.

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42 See PAC/1400 Bulkley/35, 36 where PacifiCorp effectively suggests that the Commission should jettison its understanding of the trends of UST yields against state commission authorized ROE's.

Q. PacifiCorp is concerned in PAC/1400 Bulkley/25 that Staff is using the "spot yield on the 30-year Treasury bond as of June 3 2022 as the risk-free rate in the CAPM".[43] Is that concern misplaced?

A. Yes. Staff has updated its value to reflect a more-current 30-year UST yield. However, it is extremely odd that PacifiCorp criticizes usual practice. Admittedly Staff does not torture simple models with excess complexity, because the value of simple models is that they are simple. Using forwards detracts from the efficacy of models like the CAPM

<u>GORDON GROWTH MODEL – As Check on ROE Findings</u>

Q. What is the Gordon Growth model?

A. The Gordon Growth model (or Single Stage DCF model), similarly to the Three-Stage DCF model, is based on the principle that a company's value is equal to the net present value (NPV) of all its future cash flows and the company's current stock price. The Single-Stage DCF uses simpler assumptions than other models however, with dividend payments representing the only cash flow, and an assumption that growth will remain constant in perpetuity.[44]

Q. What are the positive aspects, and potential shortfalls of the DCF model?

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[43] See PAC/1400 Bulkley/25 which suggests PacifiCorp is either obfuscating or actually does not know that Staff used normal practice in selecting a risk-free rate for CAPM.

[44] See Docket No. UG 347, Staff/1300, Muldoon Watson/31 – 39, for further discussion of the Single-Stage DCF model, and the Commission's historical treatment of its results.

A. The most positive aspect of the Single-Stage model is its simplicity. An analyst can use this model to calculate a rudimentary cost of equity valuations without needing complex inputs or analysis, beyond selecting a trusted source for the next quarter's expected dividends. In fact, after some algebraic simplification, the return can be expressed by:

$$R = \frac{D_1}{P_0} + g$$

Where $\boldsymbol{R}$ is estimated ROE, $\boldsymbol{D_1}$ is the first dividend paid after stock purchase, $\boldsymbol{P_0}$ is the stock price, and $\boldsymbol{g}$ is the growth rate.

Caution and discretion must be used when sourcing inputs to the model, for example, growth rates should be based on well vetted and reliable sources, as opposed to sell-side marketing information used by investment advisors to entice new investors. This is important to bear in mind when considering the results of any Single-Stage model, as reliance on overly optimistic inputs or use of outboard after-the-fact adjustments can have a large impact on the model output.

The Single-Stage model is based on simple principles and serves as a rough estimation of investor required ROE. It cannot incorporate known, measurable, and material information about the future usually built into Three-Stage DCF analysis. For this reason, Staff consistent with Commission precedent, has traditionally only relied on it as a sensitivity check when rate making.

Q. How does Staff determine the dividend flow and growth rate for the single-stage DCF?

A. Much like Staff's Multi-Stage DCF, Staff sources and just updated its expected dividends from Value Line. We calculate the average dividend growth rate by comparing the expected dividend by Value Line and actual dividend for each for each company in the peer screen.

Q. What inputs are used to build Staff's single-stage DCF model?

A. Staff uses the same representative draw of stock prices to build its single-stage DCF model as it uses in the three-stage DCF model. Updated dividends and anticipated dividend growth are sourced from Value Line.

Q. What are the results of Staff's Gordon Growth model?

A. Using Staff's peer utility screen, the average required ROE under Staff's Gordon Growth model is 8.9 percent. The average required ROE increased to 8.9 percent if the Company's larger peer screen is used instead. Table 8 summarizes the results of Staff's modelling.

TABLE 8[45]

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	11 = 8 + 9	13	14
	Screen #	Abbreviated Utility	UE 399 PAC	UE 399 Staff	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	ALE	60.95	4.3%	2.70	4.4%	3.5%	7.9%	1	1
2	2	Alliant	Yes	Yes	LNT	60.15	2.8%	1.81	3.0%	6.0%	9.0%	2	2
3	3	Ameren	Yes	Yes	AEE	92.17	2.6%	2.52	2.7%	7.2%	10.0%	3	3
4	4	AEP	Yes	No	AEP	97.87	3.2%	3.35	3.4%	5.8%	9.2%	4	4
5	6	Avista	Yes	No	AVA	42.82	4.1%	1.83	4.3%	4.0%	8.3%	6	5
6	7	Black Hills	No	Yes	BKH	75.40	3.2%	2.53	3.4%	5.3%	8.6%	7	6
7	9	CMS	Yes	No	CMS	68.42	2.7%	1.94	2.8%	5.9%	8.7%	9	7
8	10	Consol Ed	No	Yes	ED	97.57	3.2%	3.24	3.3%	2.4%	5.7%	10	8
11	13	Duke	Yes	No	DUK	109.00	3.7%	4.06	3.7%	2.2%	5.9%	13	11
12	16	Entergy	Yes	No	ETR	114.39	3.6%	4.30	3.8%	5.2%	9.0%	16	12
13	17	Evergy	Yes	Yes	EVERG	67.33	3.5%	2.48	3.7%	6.8%	10.5%	17	13
14	18	Eversource	No	Yes	ES	87.30	2.9%	2.70	3.1%	5.9%	9.0%	18	14
16	24	IDACORP	Yes	No	IDA	109.69	2.8%	3.25	3.0%	6.6%	9.6%	24	16
17	26	NextEra	Yes	No	NEE	82.42	2.1%	1.87	2.3%	10.2%	12.5%	26	17
18	27	NorthWestern	Yes	No	NWE	56.23	4.5%	2.56	4.6%	1.9%	6.5%	27	18
20	29	Otter Tail	Yes	No	OTTR	69.39	2.4%	1.76	2.5%	6.8%	9.4%	29	20
21	31	PGE	Yes	Yes	POR	50.61	3.5%	1.89	3.7%	6.1%	9.8%	31	21
22	32	Pinnacle	No	Yes	PNW	73.47	4.7%	3.52	4.8%	2.9%	7.7%	32	22
25	38	Southern	Yes	No	SO	74.96	3.6%	2.78	3.7%	3.4%	7.1%	38	25
26	40	WEC	No	Yes	WEC	102.78	2.8%	3.11	3.0%	7.0%	10.0%	40	26
27	42	Xcel	Yes	No	XEL	72.38	2.7%	2.08	2.9%	6.7%	9.5%	42	27
		No. of Peers:	16	9							Mean		
										Company Screen	8.9%	ROE	
										Staff Screen	8.9%	ROE	

Points toward lower end of Staff's 3 Stage DCF Modeling results.

CAPM – As Check on ROE Findings

Q. What is the CAPM?

A. The CAPM assumes that a stock's return on equity is a function of a risk-free return and a risk premium and that the risk premium should be augmented by a company's level of risk relative to the market, which is captured by Beta or β. All told, CAPM takes the form:

$$\boldsymbol{Required\ Return} = \boldsymbol{r_f} + \boldsymbol{\beta}(\boldsymbol{r_m} - \boldsymbol{r_f})$$

45 See Exhibit Staff/1805, Muldoon/4 for Staff's full Gordon Growth Model.

Where r_f is the risk-free rate and r_m is the market return. Generally, the risk-free rate is assumed to be the rate of return on bonds. Taking cues from long-standing financial modelling, Staff calculates its CAPM using the yield on 30-year and 10-year US Treasury bonds as stand-ins the risk-free rate.

Q. Should the Commission scrutinize CAPM carefully?

A. Yes. CAPM only relies on a few inputs. In this case, there are three inputs: the risk-free rate, the market return, and the choice of Beta. Although it is generally agreed that the rate of return on US Treasury bond is the proper choice for the risk-free rate, there is much discussion about what maturity should be used for Beta and the market return.

Staff have standardized on VL Betas to give apples-to-apples modeling output comparisons. Staff uses CAPM for validation rather than rate setting in past cases consistent with Commission guidance. Staff's Betas are all updated to be current for this Rebuttal Testimony.

As has been done in past rate cases, Staff uses the market risk premium calculated by Ibbotson and the implied market risk premium from Morningstar's Stocks, Bonds, Bills and Inflation 2015 Classic Yearbook, which measures average returns since 1926. These two sources imply that the risk premium would be 4.5 percent and 6.0 percent, respectively. At the time of measurement on June 3, 2022, the 30-year yield on US Treasuries was 2.94 percent.

Q. What recommendations do you have for the maximum authorized ROE according to CAPM?

A. As stated previously, Staff only uses CAPM for validation rather than rate setting due to its historic unreliability. Within Staff's peer utility screen, the estimated ROEs from Staff's CAPM under Staff assumptions average 9.5 percent. Using the Company's peer screen, the average estimated ROE observed is also 9.5 percent.

Q. Has the Commission determined that CAPM should not be relied upon as a stand-alone modeling method, but may still be used as a check on other modeling methods employed?

A. Yes. The Commission made this determination in two general rate cases in 2001 with the issuance of Order No. 01-777 and Order No. 01-787.[46]

[46] *In the Matter of Portland General Electric*, Docket No. UE 115, Order No. 01-777 at 32 (August 31, 2001). *In the Matter of PacifiCorp*, Docket No. UE 116, Order No. 01-787 at 21 (September 7, 2001).

TABLE 9[47]

Staff's CAPM Modeling Results

PAC	1.87%	Rf Rate as shown in Exhibit PAC/307 Buckley/1 -- Top Current Table	
Opening	12.63%	Mkt Return as shown in Exhibit PAC/408 Buckley/1 - Top Current Table	
Testimony	10.76%	PAC Mkt Risk Premium (MRP)	
Staff	3.010%	R_f as August 2, 2022 30 Yr UST Yields WS	Bonds & Rates (wsj.com)
	10.70%	30 Year S&P 500	
	7.69%	Staff Mkt Risk Premium MRP)	

$R_{PAC} = R_f$+Beta*MRP

Example ONLY:
Same Model Bc
Company's Infl:

	Screen #	Abbreviated Utility	UE 399 PAC	UE 399 Staff	Ticker	VL Q2 2022 Beta	ROE w VL Beta CAPM	Screen #		ROE w VL Beta CAPM
1	1	Allete	Yes	No	ALE	0.90	9.93%	1	1	12.69%
2	2	Alliant	Yes	Yes	LNT	0.80	9.16%	2	2	11.62%
3	3	Ameren	Yes	Yes	AEE	0.80	9.16%	3	3	11.62%
4	4	AEP	Yes	No	AEP	0.75	8.78%	4	4	11.08%
5	6	Avista	Yes	No	AVA	0.90	9.93%	6	5	12.69%
6	7	Black Hills	No	Yes	BKH	0.95	10.32%	7	6	13.23%
7	9	CMS	Yes	No	CMS	0.75	8.78%	9	7	11.08%
8	10	Consol Ed	No	Yes	ED	0.75	8.78%	10	8	11.08%
11	13	Duke	Yes	No	DUK	0.85	9.55%	13	11	12.16%
12	16	Entergy	Yes	No	ETR	0.90	9.93%	16	12	12.69%
13	17	Evergy	Yes	Yes	EVERG	0.90	9.93%	17	13	12.69%
14	18	Eversource	No	Yes	ES	0.90	9.93%	18	14	12.69%
16	24	IDACORP	Yes	No	IDA	0.80	9.16%	24	16	11.62%
17	26	NextEra	Yes	No	NEE	0.90	9.93%	26	17	12.69%
18	27	NorthWestern	Yes	No	NWE	0.95	10.32%	27	18	13.23%
20	29	Otter Tail	Yes	No	OTTR	0.85	9.55%	29	20	12.16%
21	31	PGE	Yes	Yes	POR	0.85	9.55%	31	21	12.16%
22	32	Pinnacle	No	Yes	PNW	0.90	9.93%	32	22	12.69%
25	38	Southern	Yes	No	SO	0.90	9.93%	38	25	12.69%
26	40	WEC	No	Yes	WEC	0.80	9.16%	40	26	11.62%
27	42	Xcel	Yes	No	XEL	0.80	9.16%	42	27	11.62%
		No. of Peers:	16	9			VL Betas			VL Betas
				Company Screen		Mean	9.5%	ROE		12.2%
				Staff Screen		Mean	9.5%	ROE		12.2%

Points to Upper Half of Staff's 3-Stage DCF Results

47 See Exhibit Staff/1805, Muldoon/3 for Staff's full CAPM model.

CONCLUSION REGARDING CAPITAL STRUCTURE AND ROE

Q. What is Staff's recommendation regarding Capital Structure?

A. Staff recommends that the Commission adopt a notional Capital Structure of 50 percent Long-Term Debt and 50 percent Common Equity. For comparison and test of reasonableness, RRA indicates that: "In the first half of 2022, the average authorized equity ratio for electric utility cases nationwide was 49.94%".[48]

Q. What is Staff's recommendation regarding ROE?

A. Staff recommends that the Commission adopt a point ROE of 9.20 percent consistent with the findings herein within a range of reasonable ROEs between 8.99 percent and 9.33 percent.

Q. Has PacifiCorp remedied the flaws in its ROE modeling?

A. No. Rather the Company proposes what it calls "reasonable adjustments" to Staff and Mr. Gorman's modeling.[49] Staff suggests that PacifiCorp proposals on inputs are excessive, but does concede that the Company demonstrates that excessive inputs into ROE modeling generate excessive outputs.

Q. Does Staff recommend that the Commission rely on the Company's utility proxy group for ROE modeling?

A. No. Staff recommends that the Commission rely on Staff's modeling group, which uses methods vetted by the Commission in many rate cases over the

[48] See Staff/1801.

[49] See PAC/1400 Bulkley/4 for an example of the type of adjustments to inputs PacifiCorp suggests for Staff's modeling, and PAC/1400 Bulkley/6 for an example of Company proposals regarding Mr. Gorman's work.

last decade. Note that Mr. Gorman's always uses a utility's proxy group as his starting point and instead focuses immediately on ROE modeling. Therefore, Mr. Gorman is not endorsing PacifiCorp's proxy group.

Q. PacifiCorp suggests that, "Mr. Gorman's criticisms of (Anne E. Bulkley) methodologies challenge the validity of his own analyses. Is that a reasonable conclusion?[50]

A. No. Given that Mr. Gorman notes the myriad flaws in PacifiCorp's ROE analysis, merely indicates that he is perceptive and aware that inflated inputs are what is causing PacifiCorp to generate outsized recommendation. Rather it would be remiss of Mr. Gorman not to point out that PacifiCorp's work is fundamentally flawed and unreliable for ratemaking.

Q. Did Staff examine Mr. Reed's ROE testimony for KWUA-OFBF?[51]

A. Yes. Staff's concern with Mr. Reeds work is that freezing PacifiCorp's Cost of Capital components to those authorized by the Commission in the Company's last general rate case appears overly generous given the downward trend in ROEs authorized in the first half of 2022.

Q. Did Staff examine Mr. Kronauer's ROE testimony for Walmart?

A. Yes. Mr. Kronauer is correct that PacifiCorp's requested ROE of 9.80 percent is counter to electric industry trends.

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[50] See PAC/1400 Bulkley/11 @7-8.
[51] See KWUA-OFBF/100 Reed/11.

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

A. Staff's calculations generate a 6.959 percent Overall Rate of Return (ROR). Though 18 bps lower than the Company last authorized ROR, this is a fair and reasonable recommendation to the Commission.

Q. Does that conclude your testimony regarding Capital Structure and ROE?

A. Yes.

5. CHANGES PROPOSED TO PCAM AND TAM

Q. Are you the Staff witness adopting the Staff Opening Testimony originally submitted by Moya Enright?

A. Yes. Ms. Enright has resigned from the OPUC and I am adopting her testimony.

Q. What does this section of testimony focus on?

A. This section focuses on the rebuttal testimony PacifiCorp submitted on the proposed changes to the TAM and PCAM as well as the direct testimonies offered by other parties on those same subjects.[52]

Q. Before beginning discussion of the testimonies offered by each of the other parties, do you have changes to Staff's contained in Ms. Enright's opening testimony regarding the TAM and PCAM, given your review of these other testimonies?

A. No, other than specifically identified in the testimony below.

Q. Please start with your review of the PacifiCorp-related testimony.

A. There are two sets of testimonies that address the TAM and PCAM changes, The PAC/1200 testimony offered by Ms. Steward, pages 25 and 26; and, the PAC/1500 testimony offered by Mr. Wilding, pages 2 to 32. There is other testimony offered dealing with whether or not changes to the TAM or PCAM affect the recommended return on equity, but I will be addressing that issue in other portions of my testimony.

Q. Please discuss Ms. Steward's testimony.

[52] Power Cost Adjustment Mechanism (PCAM); Transition Adjustment Mechanism (TAM).

A. Basically Ms. Steward states on PAC/1200, Steward/26, that PacifiCorp agrees with the Staff recommendations regarding the rate year updates including updating the hydrological forecasts. The more detailed discussion of the TAM and PCAM issues is found in Mr. Wilding's testimony.

Q. Please discuss Mr. Wilding's testimony.

A. Mr. Wilding first agrees with Staff that the updates will be limited to the three factors identified on Staff/900, Enright/8, namely the official forward price curve, latest short-term purchases and sales, and the most recent hydrologic forecast for the test year.[53]

On page two of PAC/1500, Mr. Wilding proposes timing for rate year updates occur when concurrent General Rate Case (GRC) and TAM filings are made on March 1st; namely, that the update occurs on April 1st.

Q. Does Staff support the timing for updates proposed by the Company?

A. This seems reasonable to Staff.

Q. Mr. Wilding on page 3 of his testimony discusses the factors PacifiCorp considers in deciding whether to change the December water supply forecast. Do you support PacifiCorp having the discretion as to whether to make a hydrologic forecast revision?

A. No. PacifiCorp should not be the sole party deciding on whether the updates should occur on the schedules specified, including whether or not the Company thinks the update is material. Either the update should be required to be filed, or PacifiCorp can obtain the consent of Staff, and at least one other

53 PAC/1500, Wilding/2, lines 10-12.

party to the docket that the update would not represent a material change and is therefore not necessary.

Q. On page 4 of Wilding's reply testimony, beginning on line 15, Mr. Wilding notes he does not support your recommendation of requiring PacifiCorp to notify the parties within 5 business days of a correction or omission being identified by the Company with corrections and associated documents filed within ten business days. Please discuss this portion of Mr. Wilding's testimony.

A. Mr. Wilding does not agree with Staff's recommendation requiring testimony and data requests being updated and recommends that requirement be deleted. Mr. Wilding also softens the ten-business day requirement where the Company can notify parties if it is unable to meet the ten-day deadline and provide an alternate timeline.

I do not support the changes except for requiring revising responses to data requests. Staff accepts deletion of the words "and/or data requests" from the proposed text on Staff/900, Enright/14; and, otherwise the proposed verbiage should remain intact.

Maintaining a ten-business day requirement will help ensure that PacifiCorp plans its resources to be able to meet that requirement. The proposed PacifiCorp language allows for the ten-day requirement to be breached and is in essence relaxes the requirement. Given that Staff is supporting these updates, such as the hydrologic update, which would appear to reduce much power cost risk to the Company, it is reasonable for PacifiCorp to take on this reporting obligation. Therefore, on PAC/1500, Wilding/5, the proposed language on lines 25 through 29, beginning with “In the event.” should be rejected.

Q. On PAC/1500, Wilding/6, Mr. Wilding discusses an alternative of a workshop to provide a forum on its work papers and identify any additional materials parties may see as lacking. Do you support that suggestion?

A. Yes. I support trying that as an option to help ensure that parties have the necessary documents and work papers, above and beyond what PacifiCorp provides as necessary to meet the filing requirements and guidelines.

Q. Beginning on PAC/1500, Wilding/7, the testimony disputes Staff testimony and recommendations against PacifiCorp PCAM changes. Does that PacifiCorp testimony give you cause to rethink your PCAM recommendations?

A. No. There are at least three changes underway that lead me to conclude that it is premature to make radical changes to the PCAM structure. First, with the update recommendations Staff is supporting, that should reduce risks in power cost forecast. Second, PacifiCorp power cost forecast risk should also be reduced through the pass-through of QF power purchase contracts. And third, the power cost model is changed to using Aurora from Grid. These are three major changes to the TAM and should provide greater forecast accuracy as well as reduce forecast risk. I think it is premature to address major changes in the PCAM structure.

Q. Do you still support the PCAM change of having symmetric deadbands of +/- $30 million?

A. Yes. Even though Mr. Wilding dismisses that proposal on PAC/1500, Wilding/14, I still believe it is a reasonable recommendation for the Commission to consider.

I agree with the Company that the distribution of actual power costs has changed with changes in the mix of resources and the other factors cited on PAC/1500, Wilding/11. However, the Company errors in conflating a distribution change with an expected value change.

Q. What do you mean by the distribution of power costs?

A. The distribution of power costs means the different power costs that could occur, given the resources available, under different circumstances such as weather, natural gas prices, plant outages and performance and loads. In this regard, I am thinking of a Monte Carlo analysis where lots of different games are played to see what possible power costs are available given a set of resources. While a distribution might change with a different mix of resources that does not mean there is a missed inherent bias in which way the expected value or midpoint changes.

Q. Please continue.

A. While the Company is complaining that it has ended up with the short-end of the stick when comparing actual to forecasted power costs, the three changes discussed earlier as well as moving to symmetrical dead bands are significant enough to lead me to conclude that we should first assess the impacts of these changes before we declare that this is a rigged game as PacifiCorp claims.[54]

Q. Does Mr. Wilding challenge your finding that PacifiCorp's size and scope make it more able to absorb variance in actual power costs?

A. No. Mr. Wilding instead focuses on the fact that PacifiCorp is absorbing costs but does not address the fact that PacifiCorp has more financial heft.[55]

Q. Please move on to AWEC witness Mullins. On AWEC/100, Mullins/29, Mr. Mullins states a concern about how direct access will be handled given the update mid-year. Do you agree?

A. Yes. PacifiCorp did not address this concern in Mr. Wilding's testimony other than to say we should make changes to reduce forecast risk. PacifiCorp should provide a process, or explain how current processes are adequate, for direct access pricing schedule changes such that these changes in the TAM does not create any incentive for potential direct access customers to depart or remain on PacifiCorp's system. In other words, we should not have a mismatch of direct access and cost of service rates as identified in AWEC/100, Mullins/29, lines 15-20.

Q. On AWEC/100, Mullins/32, Mullins begins to discuss three changes to TAM guidelines which are to have a seven-calendar day discovery period, have filings occur on March 1 of all years, and use a base

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[54] PAC/1500, Wilding/10, lines 17-21.
[55] PAC/1500, Wilding/14, lines 1-8.

calendar period. PacifiCorp opposes all three changes. What is Staff's view?

A. With regards to the seven-calendar day discovery recommendation, I agree with Mr. Wilding that the early workshop should aid in discovery efforts such that the concern giving rise to AWEC's seven-day discovery period proposal is unnecessary.[56] I recommend the parties revisit this issue after we have had in practice the envisioned workshop.

With regards to the March filing date, I support AWEC's objective. It does seem curious that PacifiCorp can meet the dates when filing a GRC but not in other instances absent a herculean effort.[57] As an alternative for Commission consideration, perhaps March 15, is a reasonable resolution.

With regards to the calendar year base period, PacifiCorp's concerns seem reasonable and so I do not support this AWEC recommendation.[58]

Q. On AWEC/100, Mullins/37, Mullins does not support the move to symmetrical deadbands. Why do you disagree?

A. Staff supports the move to symmetrical deadbands because it is reasonable to conclude that the distribution of potential power costs has changed from when the deadbands were first developed. Mr. Mullins does not dispute these changes.[59] If the changes have occurred, it is reasonable to assume the

56 PAC/1500, Wilding/29.
57 PAC/1500, Wilding/30, line 9.
58 PAC/1500, Wilding/30.
59 AWEC/100, Mullins/37.

distribution has changed and hence the design of the deadbands should change as well to reflect a reasonable allocation of risks.

Q. Do you agree that the earnings test should not be changed for the PCAM as discussed in AWEC/100, Mullins 38?

A. Yes. To provide cost recovery while balancing the interests of customers and the Company, having a 100 ROE basis points range is reasonable. I have not seen any argument from the Company that is compelling to revise this long-standing precedent. Further, we are making substantive changes to the TAM that reduces the Company's risk.

Q. Please discuss Mr. Gehrke's testimony on behalf of CUB. On CUB/200, Gehrke/9, Mr. Gehrke states that PacifiCorp's end goal is to have 100 percent of prudent power costs recovered from customers, that is a 100 percent true-up. Does PacifiCorp agree?

A. Yes.[60] And that statement by PacifiCorp is troubling to Staff in the sense that PacifiCorp should have a forceful incentive to minimize costs. Having a 100 percent true-up essentially removes that from being in place. It is important to have alignment between the customer and Company incentives. The current PCAM design aligns incentives. While the Company states that it wants a reasonable balance of risks, and that the balancing of risks have been altered from what was originally established, PacifiCorp is proposing an end goal that dramatically departs from the original balancing of risks. PacifiCorp is seeking

[60] PAC/1500, Wilding/24, line 12.

an end goal to place all market risk on customers.[61] The Commission should maintain its current policies that both aligns incentives and balances risks between the Company and customers. That is what Staff had as its purpose in proposing changes to the TAM and PCAM.

Q. CUB/200, Gehrke/13, notes that the PCAM will trip for PacifiCorp for the 2021 power costs. Does PacifiCorp acknowledge that point in its reply testimony?

A. Not in effect. I do not believe the table shown in PAC/1500, Wilding/8, shows for 2021 the amount not ultimately recovered in rates from customers. From that standpoint, PacifiCorp overstates the impact of the current PCAM procedures.

Q. Does this conclude your testimony?

A. Yes.

[61] For example, see PAC/1500, Wilding/11.

CASE: UE 399
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1801

Average Authorized ROE and Capital Structure in U.S. Electric Utility Rate Cases Decided in the First Half of 2022

August 11, 2022

RRA Regulatory Focus

Major Rate Case Decisions

July 27, 2022

Major energy rate case decisions in the US –

January-June 2022

Lisa Fontanella, CFA Research Director

The average electric and gas authorized returns on equity remain at all-time lows as per averages calculated for the first half of 2022.

For detailed data

Access RRA's electric and gas rate cases as of the first half of 2022 data tables.

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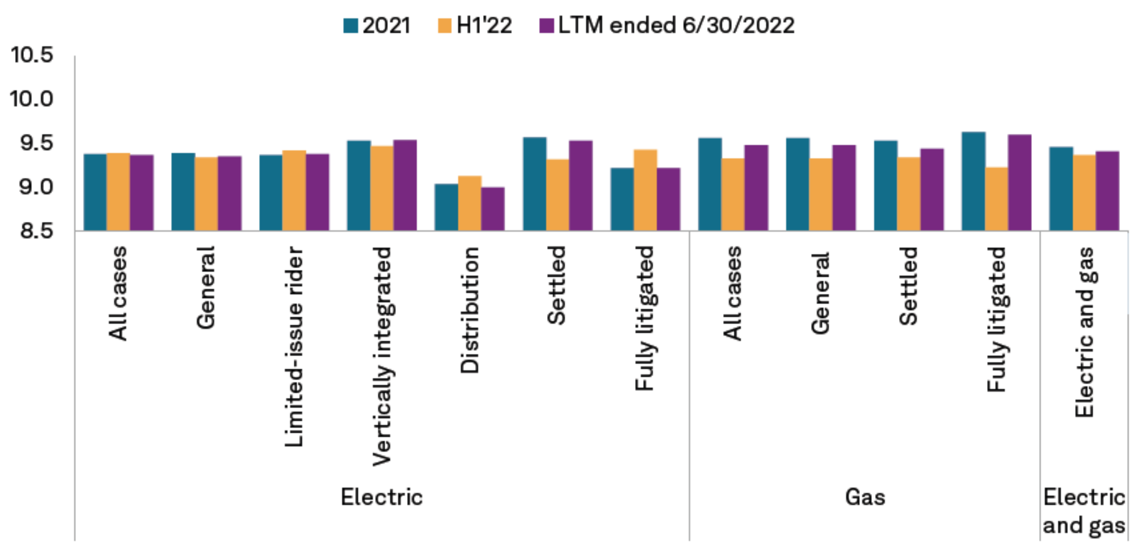
Executive Summary

Introduction

The average electric and gas authorized returns on equity remain at all-time lows as per averages calculated for the first half of 2022.

The average authorized return on equity for electric utilities was 9.39% in rate cases decided in the first half of 2022 — in line with the 9.38% average for full-year 2021. There were 19 electric ROE authorizations in the first half of 2022 versus 55 in full-year 2021.

Average authorized return on equity (%)



Electric averages	2021	H1'22	LTM ended 6/30/2022
All cases	9.38	9.39	9.37
General rate cases	9.39	9.34	9.35
Limited-issue rider cases	9.37	9.42	9.38
Vertically integrated cases	9.53	9.47	9.54
Distribution cases	9.04	9.13	9.00
Settled cases	9.57	9.32	9.53
Fully litigated cases	9.22	9.43	9.22
Gas averages			
All cases	9.56	9.33	9.48
General rate cases	9.56	9.33	9.48
Settled cases	9.53	9.34	9.44
Fully litigated cases	9.63	9.23	9.60
Composite electric and gas averages			
Electric and gas	9.46	9.37	9.41
U.S. Treasury			
30-year bond yield	2.06	2.65	2.29

Data compiled July 22, 2022.
LTM = Last 12 months.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; U.S. Department of the Treasury

The average authorized ROE for gas utilities was 9.33% in cases decided in the first half of 2022 versus 9.56% in full-year 2021. There were nine gas cases that included an ROE determination in the first half of 2022 versus 43 in full-year 2021.

Amid ongoing COVID challenges, 2021 was a record year in terms of rate case activity, which neared all-time highs with over 150 decisions issued by state public utility commissions — the highest level since the early 1980s.

While the reasons for a rate case filing are numerous, the main driver continues to be 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, and the impact of broader economic and sector-wide forces on operations.

About this report

This report, which is updated quarterly, offers a detailed overview of completed electric and gas rate case decisions in the U.S. 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 that involve significant rate base additions that are recognized outside of a general rate case. In some of these cases, the rate change coverage criteria may not apply. In an effort to align data presented in this report with data available in S&P Global Market Intelligence's online database, earlier historical data provided in previous reports may not match historical data in this report due to certain differences in presentation, including the treatment of cases that were withdrawn or dismissed, as well as the addition of cases that were not included previously as part of RRA's coverage.

The Take

Averages calculated for the first half of 2022 show electric and gas authorized returns on equity remain at all-time lows. Rate case activity for investor-owned electric and gas utilities in the U.S. has been at elevated levels in recent years and neared-all time highs in 2021 with more than 150 rate cases decided — the highest level since the 1980s. With interest rates on the rise, RRA anticipates rate case filings will remain robust.

Authorized returns may edge slightly higher going forward as the U.S. Federal Reserve continues efforts to tamp down soaring inflation via a series of interest rate hikes, the first of which was announced in March. The effect of future interest rate increases by the Federal Reserve on authorized returns is unlikely to be dramatic, however, as state utility regulatory commissions have generally taken a more gradual and measured approach to changes in authorized ROE levels.

State regulatory support and the authorization of adequate returns to ensure ongoing capital attraction in the utility sector will be instrumental as the industry shifts away from fossil fuels to renewables and storage and invests in strengthening the nation's power grid against climate and other risks.

Overview of electric and gas authorizations

The average electric and gas authorized returns on equity for the first half of 2022 remain at all-time lows.

The average authorized return on equity for electric utilities was 9.39% in rate cases decided in the first half of 2022 — largely in line with the 9.38% average for full-year 2021. There were 19 electric ROE authorizations in the first half of 2022 versus 55 in full-year 2021.

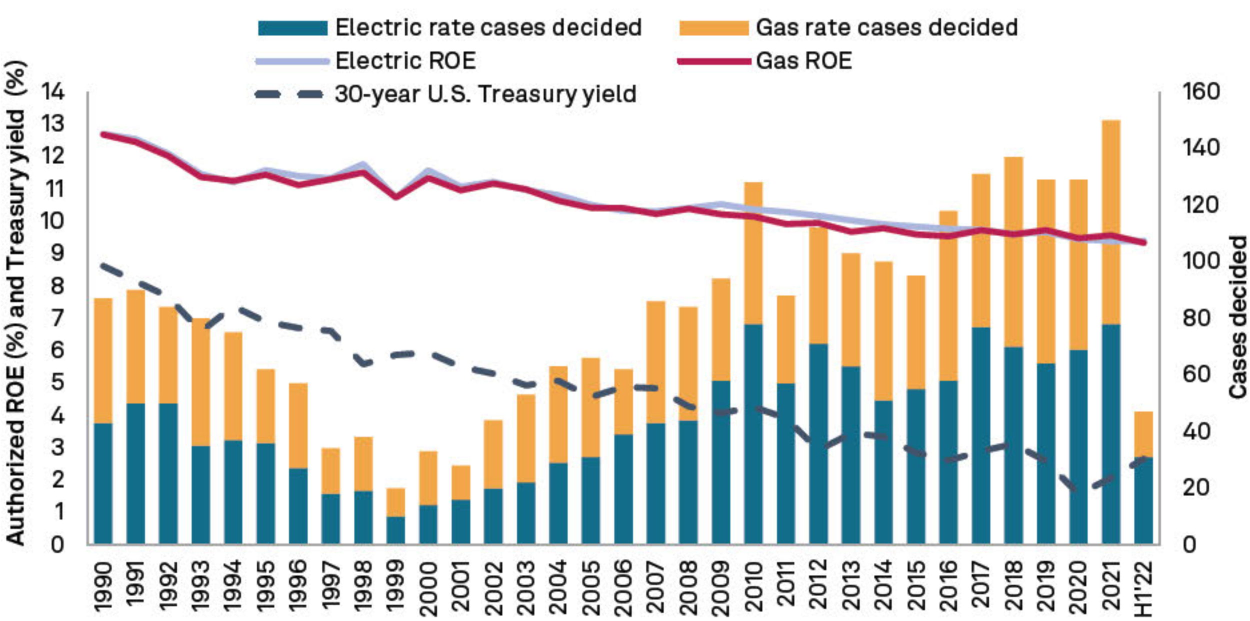
The average authorized ROE for gas utilities was 9.33% in cases decided in the first half of 2022 versus 9.56% in full-year 2021. There were nine gas cases that included an ROE determination in the first half of 2022 versus 43 in full-year 2021.

The electric data set includes several limited-issue rider cases, however, excluding the rider cases makes little difference in the average ROE. Historically, the annual average authorized ROEs in electric cases that involved limited-issue riders were meaningfully higher than those approved in general rate cases, driven primarily by substantial ROE premiums authorized in generation-related limited-issue rider proceedings in Virginia. However, these premiums were approved for limited durations and have since begun to expire. As a result, the gap between the average ROE in the rider cases and in general rate cases has narrowed. In the gas industry sector, there has not been much use of limited issue rider cases as most of the gas riders rely on ROEs approved in a previous base rate case. Excluding rider cases, the average authorized ROE for electric cases was 9.34% in the first half of 2022 versus 9.39% in full-year 2021.

In the first half of 2022, the median ROE authorized in all electric utility rate cases was 9.20%, versus 9.38% in full-year 2021; for gas utilities, the metric was 9.25% in the first half of 2022, versus 9.60% in full-year 2021.

Looking at the 12 months ended June 30, 2022, the average ROE authorized in all electric utility rate cases was 9.37% and the median was 9.35%. For gas utilities in the 12 months ended June 30, 2022, the average was 9.48% and the median was 9.45%.

Average electric and gas authorized ROEs and total number of rate cases decided



Data compiled July 22, 2022.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; U.S. Department of the Treasury

The full-year averages in recent years are at the lowest levels ever witnessed in the industry. The electric ROE average in 2021 was weighed down by three ROE determinations in Illinois and Vermont that were calculated utilizing a formulaic approach tied to U.S. Treasury bond yields. Excluding these three ROE determinations, the average return authorized for electrics in 2021 was 9.47%.

The 2021 calendar-year results reflect the low-interest-rate environment and the regulatory reaction to COVID-19 challenges.

Looking longer-term, interest rates, as measured by the 30-year U.S. Treasury bond yield, fell almost steadily from the early 1980s until 2015 or so, placing downward pressure on authorized ROEs. Even though the decline in authorized ROEs was less dramatic in the period since 1990, average authorized ROEs fell below 10% for gas utilities in 2011 and for electric utilities in 2014. The calendar-year averages hovered between 9.5% and 9.8% through 2019, falling below 9.5% for the first time in 2020.

These declines in ROE have coincided with an upswing in rate case activity. There have been 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 does not include withdrawn cases. At over 150 cases, rate case activity in 2021 was the most robust observed in any year during the 1990-2021 period. In 2019 and 2020, there were about 130 cases decided annually.

Absent the pandemic, increased costs associated with environmental compliance, generation and delivery infrastructure upgrades and expansion, renewable generation mandates, storm and disaster recovery, cybersecurity and employee benefits have contributed to an active rate case agenda over the last decade.

Due to COVID-19 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. In 2021, utilities were back before state regulators seeking the highest combined increase in electric and gas rates since RRA began tracking rate cases.

Currently, there are almost 115 electric and gas rate cases pending. With interest rates now on the rise, RRA anticipates that 2022 will be another fairly active year for rate determinations, even if it does not quite match the 2021 case total.

With inflation running at multi-decade highs, the Federal Reserve, has increased its benchmark interest rate several times since March 2022. Additional hikes are expected throughout 2022, as the Fed has signaled that aggressive steps will be taken to combat high and persistent inflation pressures.

The recent hikes come after a long period of low interest rates. Following the financial crisis, the Fed cut its benchmark interest rate to near zero, and after holding rates at that level for several years, the Fed began raising rates in 2015. After several cuts in 2019, due to signs of a slowing economy, the Fed again slashed rates to near zero in March 2020 amidst the COVID-19 pandemic.

While changes in the benchmark interest rate do not move in lockstep with longer-term treasuries, and authorized ROEs do not move in lockstep with interest rates, the expectation is that as interest rates change, authorized ROEs would change in a similar fashion. However, several factors impact the timing and magnitude of such a shift. For example, normal regulatory lag — the amount of time it takes for a utility to put together a rate case filing and tender it to the commission and then for the commission to process the case — would without any other influences delay a change in average authorized ROEs relative to interest rates.

It is also worth noting that while both interest rates and authorized ROEs have generally been declining since 1990, the gap between authorized ROEs and interest rates widened somewhat over this period, largely as a result of regulators' often-unstated understanding that the drop in interest rates caused by Federal Reserve 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 more recent periods, with the focus on affordability and the need to maintain universal service during the pandemic, regulators were more apt to lower authorized ROEs to mitigate the level of bill increases.

With interest rates now on the rise, the average authorized returns for full year 2022 and 2023 may edge higher, albeit at a moderate pace as state utility regulatory commissions generally have taken a more gradual and measured approach to changes in authorized ROE levels. In addition, affordability concerns are likely to continue as regulators grapple with rate increases stemming from the recovery of pandemic-related costs and stranded costs related to the energy transition. These considerations could be further impacted by the overall state of the economy, rising natural gas prices and the significant level of planned capital spending expected in the industry, particularly to fund the energy transition.

Capital structure trends

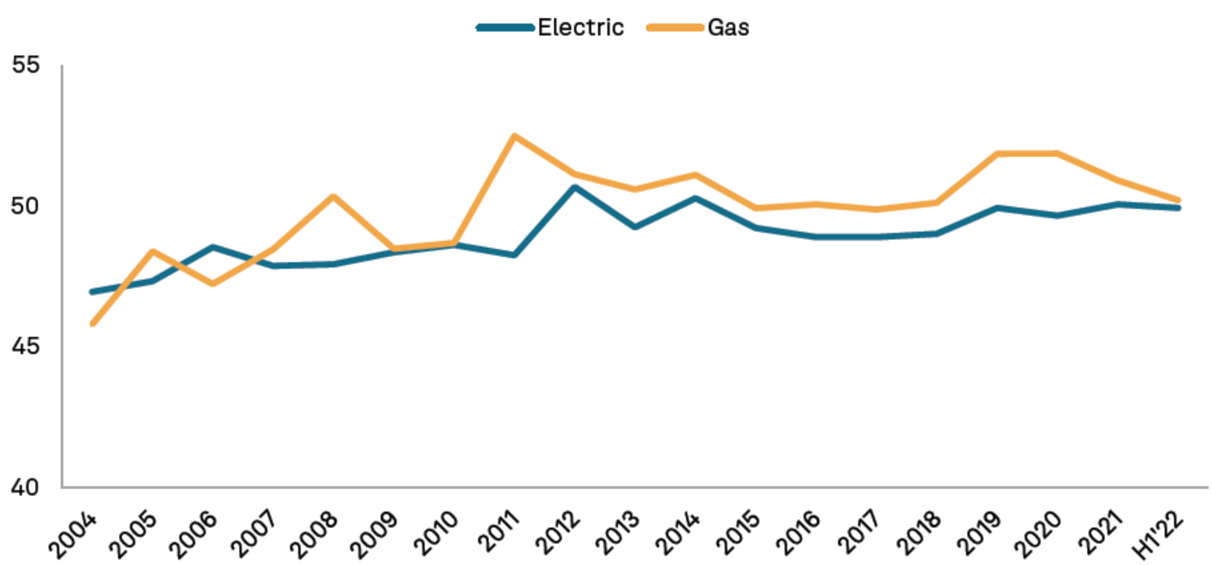
The negative cash flow impact of federal tax changes that took effect in 2018 raised concerns regarding utility liquidity and credit metrics. In response, many utilities sought higher common equity ratios, and the average authorized equity ratios adopted by utility commissions in 2019 were modestly higher than the levels observed in 2018 and 2017.

For full years 2021, 2020, 2019, 2018 and 2017, the average equity ratios authorized in electric utility cases were 50.06%, 49.69%, 49.94%, 49.02% and 48.90%, respectively. The average equity ratios authorized gas utilities were 50.92%, 51.87%, 51.86%, 50.12% and 49.88%, respectively.

In the first half of 2022, the average authorized equity ratio for electric utility cases nationwide was 49.94%. For gas utilities, the average authorized equity ratio nationwide was 50.21%.

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 electrics.

Average authorized equity ratio (%)



Data compiled July 22, 2022.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

A more granular look at ROE trends

The discussion thus far has looked broadly at trends in authorized ROEs; the sections that follow provide a more granular view.

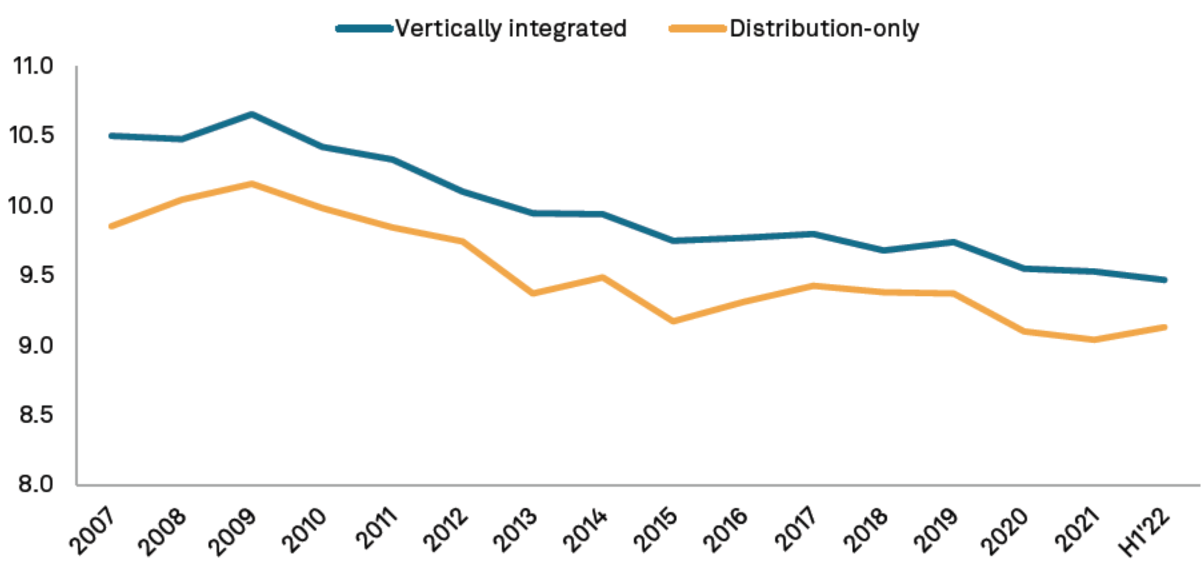
RRA has observed that there can be significant differences between average ROEs based upon the types of proceedings/decisions in which these ROEs were established.

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, which involve generation, have been about 30 to 65 basis points higher than in distribution-only cases, arguably reflecting the increased risk associated with ownership and operation of generation assets.

The industry average ROE for vertically integrated electric utilities was 9.47% in cases decided in the first six months of 2022, versus the 9.53% average posted in full year 2021. For electric distribution-only cases, the industry average ROE was 9.13% in the first six months of 2022, versus 9.04% in full year 2021.

Average authorized electric ROEs (%)

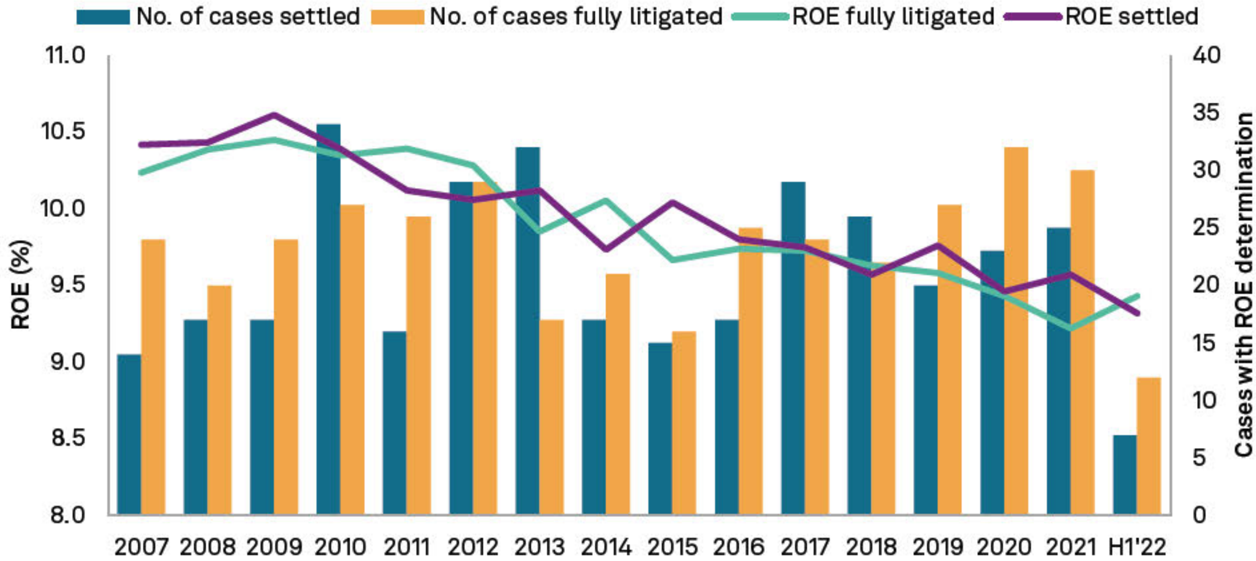


Data compiled July 22, 2022.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

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. However, some states preclude this type of treatment, and settlements must specify these values, if not the specific adjustments from which these values were derived.

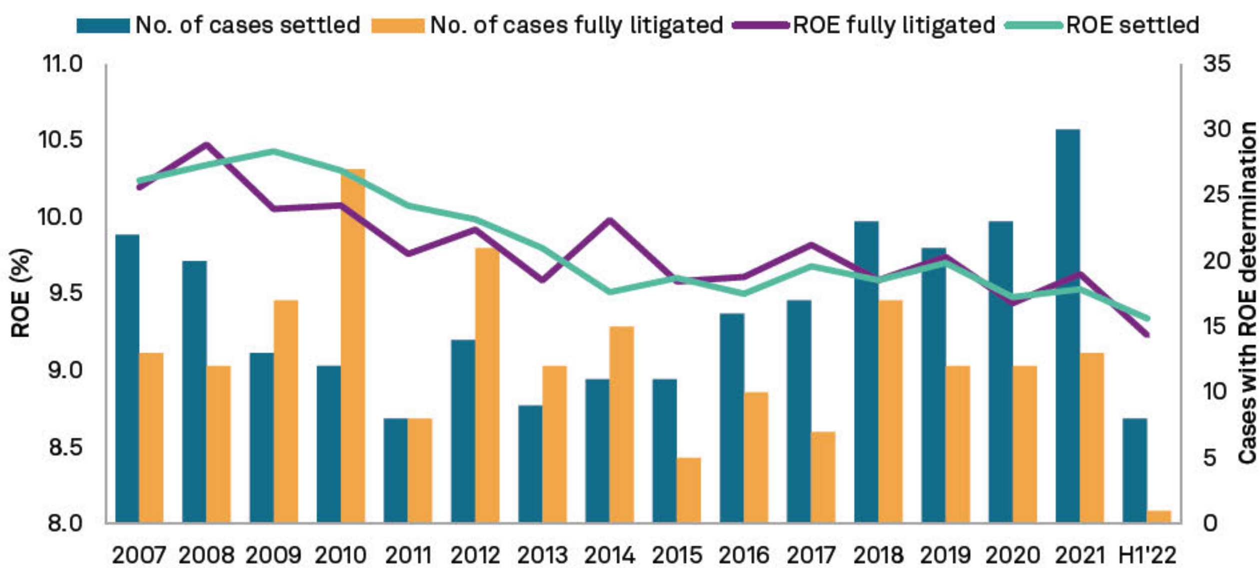
For both electric and gas cases, RRA has found no discernible pattern in the average authorized ROEs in cases that were settled versus those that were fully litigated. In some years, the average authorized ROE was higher for fully litigated cases, while in others, it was higher for settled cases.

Average authorized electric ROEs: settled vs. fully litigated cases



Data compiled July 22, 2022.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

Average authorized gas ROEs: settled vs. fully litigated cases



Data compiled July 22, 2022.
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 by quarter since 2017, 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 by quarter since 2020.

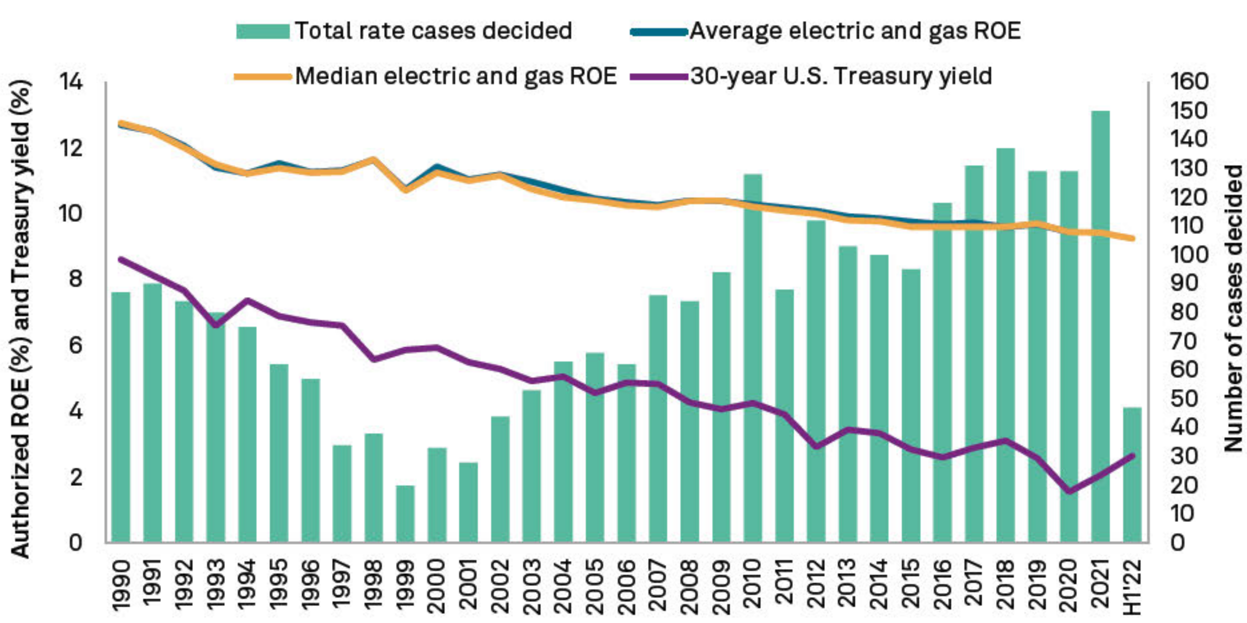
Tables 3 and 4 provide comparisons since 2007 of average authorized ROEs for settled versus fully litigated cases, general rate cases versus limited-issue rider proceedings and vertically integrated cases versus delivery-only cases for electric and gas utilities, respectively.

The individual electric and gas cases decided in the first half of 2022 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 either the average currently authorized ROEs for utilities industrywide or the returns actually 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 that has occurred over this time frame.

Composite electric and gas average authorized ROEs and total number of rate cases



Data compiled July 22, 2022.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; U.S. Department of the Treasury

Further Reading

The rate case process: a conduit to enlightenment

Rate base: How would you rate your knowledge of this utility industry fundamental?

Adjustment Clauses — a State by State Overview

Adjustment Clauses — Data tables

Major Utility Cases in Progress in the US

Major Utility Cases in Progress in the US - Databook

Major utility cases in progress — Pending significant non-rate case activity

Utility Asset Securitization in the U.S.

State Regulatory Evaluations – Energy

Utility Capital Expenditures Update — Energy and water utility capex plans on-track for record breaking 2022

State lawmakers zero in on electric vehicles, nuclear generation during Q1'22

US regulators juggle stranded cost recovery, abatement strategies

Gas Ban Monitor: West Coast pushes new boundaries; pro-gas state bills stall

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 nearly 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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STAFF EXHIBIT 1808

ROE: Financial News that Investors in Electric Utilities Are Seeing

August 11, 2022

News Articles Cited

Aggressive Now, Pause Later

Moody's – Jul. 7, 2022

The minutes from the June meeting of the Federal Open Market Committee didn't contain a ton of surprises. The central bank is worried that if it doesn't aggressively remove monetary policy accommodation, inflation could become entrenched. Participants judged a 50- or 75-basis point rate hike at the July meeting would be appropriate. The minutes are dated, and inflation expectations have dropped recently along with commodity prices. Still, the incoming data on consumer prices could determine if it is a 50- or 75-basis point rate hike. The minutes noted that policy would need to be even more restrictive.

Since the minutes, market-based measures of inflation expectations have dropped and are consistent with where the Fed would want them. Also, the jump in the University of Michigan's measure of inflation expectations, which spooked the Fed, has been revised away. The June CPI will likely determine how aggressive the Fed is this month. Our preliminary forecast is for the CPI to have risen 1.1% between May and June. This would be the second consecutive monthly gain of at least 1%.

There were a few references to tighter financial market conditions, which are doing some of the work for the Fed. Monetary policy primarily affects the economy via financial market conditions. Therefore, the Fed is getting exactly what it wants: lower stock prices, higher Treasury yields, and wider corporate bond spreads

Pause is possible

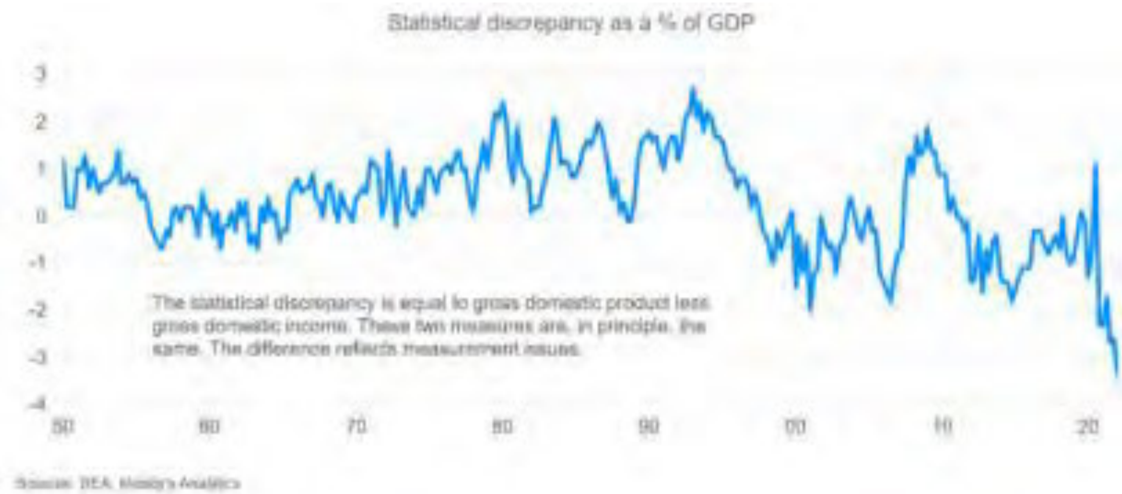
The front-loading of rate hikes gives the Fed the flexibility to pause, which the minutes alluded to. Once the target range for the fed funds rate is at its neutral rate of 2.5%, the Fed may pause to assess how the removal of monetary policy is affecting the economy, inflation and the outlook.

Fed officials don't seem concerned about a recession. There was no reference to recession in the minutes. Also, the Fed described the labor market as very tight. The minutes did highlight some downside risks to the outlook, including further tightening in financial market conditions that would be a larger drag on the economy. This is a subtle sign that the Fed has financial market conditions roughly where it would like them and further tightening could concern the central bank.

Fed gives shout out to GDI

The Fed didn't avoid discussing the drop in first-quarter GDP and the prospect that it didn't do well in the second quarter. However, the minutes referenced gross domestic income, which has held up better than GDP.

The difference between real GDP and real GDI, also known as the statistical discrepancy, has never been so large. The Bureau of Economic Analysis, the government agency that constructs these estimates, may be having an especially difficult time accurately measuring real GDP in the pandemic given the resulting big swings in global trade and inventories. If so, the BEA could ultimately revise GDP up to be more consistent with real GDI. It is also possible that the BEA is overstating corporate profits. The strength of GDI is likely one reason the Fed doesn't seem concerned about a recession.



High-yield spreads will widen further

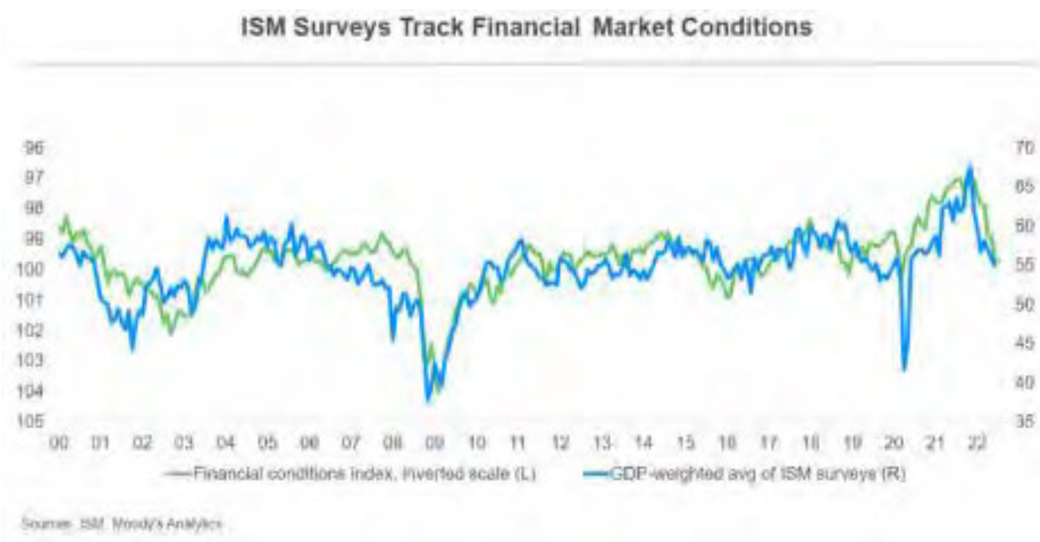
U.S. high-yield corporate bond spreads have widened noticeably this year and likely have not peaked as the economy continues to cool and volatility in equity markets remains above historical averages. The current high-yield corporate bond spread would put the odds of a recession at 33%. This would potentially be a reason for optimism, since the credit cycle normally leads the economic cycle. However, the **investment-grade corporate bond spreads put** the **recession odds** at **52%.**

For now, volatility isn't out of line with economic fundamentals. To estimate the level of the VIX consistent with fundamentals, we model the monthly average of the VIX using an ordinary least squares regression. Independent variables include the GDP-weighted average of the ISM surveys, financial market stress, a dummy variable for recessions, and U.S. economic policy uncertainty.

The results were in line with our a priori, as all coefficients had the expected sign. All were statistically significant and had an adjusted r-squared of 0.62. The regression was re-estimated, but we replaced U.S. economic policy uncertainty with global policy uncertainty. The assumption is that uncertainty abroad would affect volatility in U.S. equity markets. However, the results showed this explained less of the variation in the VIX than U.S. policy uncertainty.

Overall, the VIX isn't out of line with fundamentals, so the widening in spreads for high-yield corporate bonds shouldn't be surprising. A model we built to forecast high-yield corporate bond spreads uses the ISM surveys, and odds are that they will decline further, implying further widening in the spreads. The high-yield corporate bond spread is currently 583 basis points, more than an average spread of 350 basis points outside of a recession.

Spreads are still noticeably tighter than the 1,000-point average spread during the past three recessions. The baseline forecast doesn't assume a recession, therefore spreads shouldn't come anywhere close to the average seen over the past three recessions. Though U.S. GDP could decline in the first half of this year, other data don't signal a recession, including the **ISM manufacturing** and **nonmanufacturing surveys**.



ISM Surveys Track Financial Market Conditions

Sources: ISM, Moody's Analytics

Both of the **ISM surveys declined in June**, **but neither** are **near levels** that have **historically signaled** a **recession**. The GDP-weighted average of the ISM surveys tracks financial market conditions. Financial market stress so far in July points to further ISM survey declines, though they would not be as significant as in prior months. There is still some cushion as the GDP-weighted average of the ISM surveys remains above its neutral threshold of 50.

–

Analysts See Stable Utility Sector Stocks Poised to Ride Out Potential Recession

by Allison Good – S&P Global Market Intelligence – Jul. 5, 2022

Fears of a recession are rising as the S&P 500 index extends its losses, but industry experts anticipate the utilities sector will remain an important **flight to safety**.

Performance by U.S. utility stocks during previous economic downturns, a decreasing sensitivity to interest rates and stable earnings and dividend growth suggest the sector could see substantial price upside despite signs of a looming recession, industry experts said.

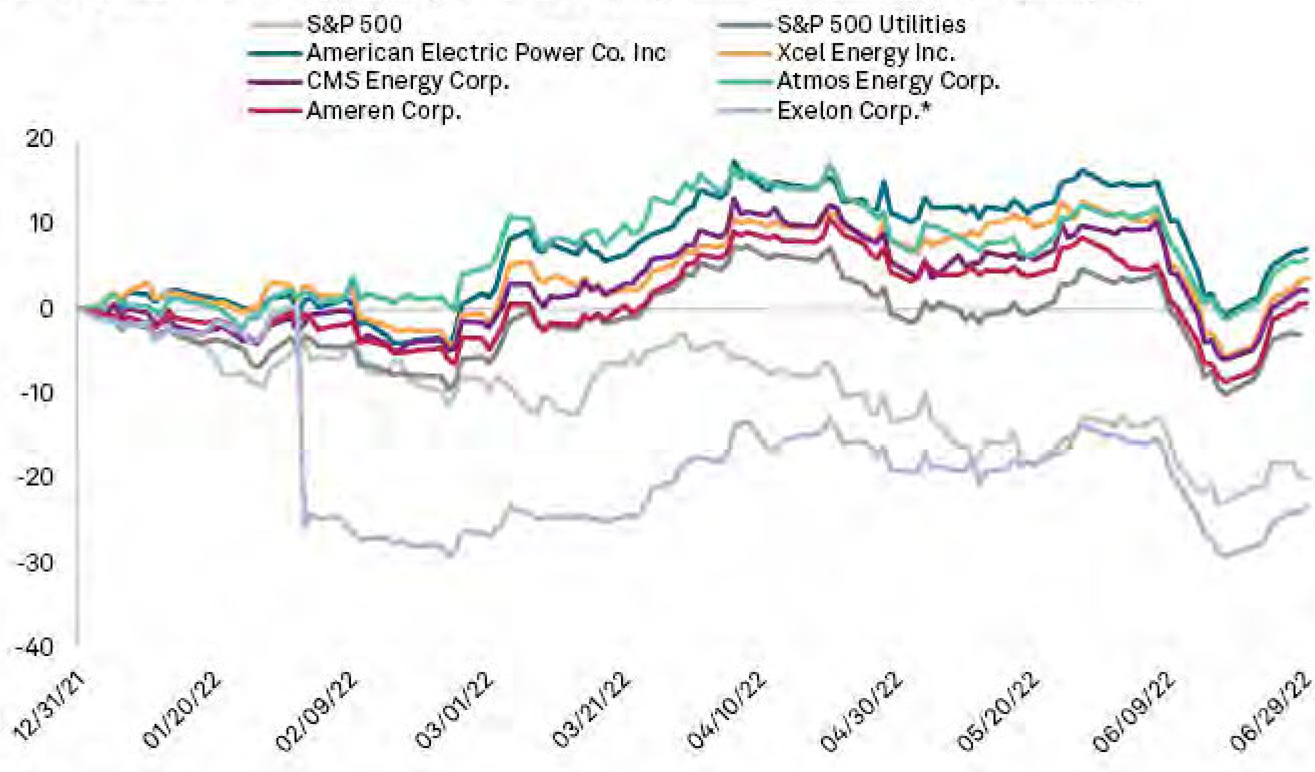
Utility share prices' recent deconsolidation from inflation has transformed the industry from a steady-growth, defensive play to a higher-growth sector that can increase earnings and return material capital to investors during economic dips. **So far in 2022**, the **S&P 500 Utilities index** has **lost just 3%** of its **value** as of the June 28 market close, **compared** to the **broader S&P 500 index's** nearly **20% drop**.

Historically, according to analysts at Morgan Stanley, the utility sector's highest stock market outperformance has occurred 12 months before a recession and three months into a recession, suggesting that "the space trades higher on a relative basis well in advance of an actual recession, holds its value on a relative basis until the recession hits, then sees another period of outperformance shortly after a recession begins."

Morgan Stanley said it **does not expect utility stocks to rise** "**on** an **absolute basis**," **but** thinks "**relative performance** will be **favorable in** a **downturn**." Utilities' price-to-earnings ratios, Morgan Stanley added in a June 29 note to clients, also offer "a neutral risk/reward proposition from a valuation standpoint when compared to other defensive cohorts."

UBS analysts wrote June 30 that investors should still orient their North American utility and power stock picks toward "valuation and yield in stocks with lower risk fundamentals to the accelerating growth from the clean energy transition." This strategy, in UBS' view, sets investors up over the long term to own the stocks most likely "to emerge as the new top-quartile names at the next (price-to-earnings ratio) valuation spread peak."

Utility stocks steady despite market turmoil, recession worries (%)



As of June 29, 2022.
* Exelon Corp.'s share price was affected by the Feb. 23, 2022 spin-off of Constellation Energy.
Source: S&P Gloal Market Intelligence

Morgan Stanley sees investors increasingly attracted to "low-risk, discounted" utility companies like American Electric Power Co. Inc., Exelon Corp. and Atmos Energy Corp., and that CMS Energy Corp., Ameren Corp. and Xcel Energy Inc. still have untapped stock price upside as well.

John Bartlett, president of utilities-focused investment portfolio manager Reaves Asset Management, said in an interview he expects the industry to grow earnings per share by 5% to 6% and pay dividend yields of 3% to 3.5% per year on average even during a recession.

"The backdrop for them providing that consistent earnings growth and an above-market dividend rate is very sustainable," Bartlett explained. "You can count on the sort of slow stair steps of value added to shareholder returns over time … you probably have better visibility into how you're going to get rewarded for your patience" compared to other sectors that investors might turn to as the possibility of a recession rises

Analysts at Scotiabank agreed that utility stocks should be less volatile than the overall market during a downturn, though Morgan Stanley does anticipate earnings growth will slow into 2023 even without a recession.

During a June 14 investor conference, NextEra Energy Inc. President and CEO John Ketchum said the company will have the same cash flow and capital access advantages despite inflation and a potential downturn.

"Don't ever forget we are a cash flow machine. ... If you were ever concerned about the growth maybe slipping a bit, which we are not, then remember the [capital expenditure] opportunities would go down at the same time," Ketchum said. "We'd be enormously free-cash-flow positive, and we'd be able to buy back shares and achieve our EPS expectations."

A high interest-rate environment also gives NextEra "even more headroom when we go to compete against the unrated wind developers, the unrated solar developers, the unrated storage developers" for debt and equity, he continued.

At the Edison Electric Institute's recent annual conference, top utility executives reiterated plans to spend tens of billions on transitioning to cleaner energy sources, with the vast majority of that spending allocated toward regulated assets, even in the face of economic headwinds.

Still, utilities grappling with issues ranging from regulatory support to climate, and slower load and earnings growth could face a higher stock price risk during a recession, according to Morgan Stanley, which named PG&E Corp., Edison International, Entergy Corp., Consolidated Edison Inc., Pinnacle West Capital Corp. and PPL Corp. as utility holdings companies unlikely to perform as well.

UBS agreed that "taking a valuation-driven, low-risk approach and moving to a stock-picking focus versus a defensive sector approach is key to navigating the less bullish backdrop moving forward."

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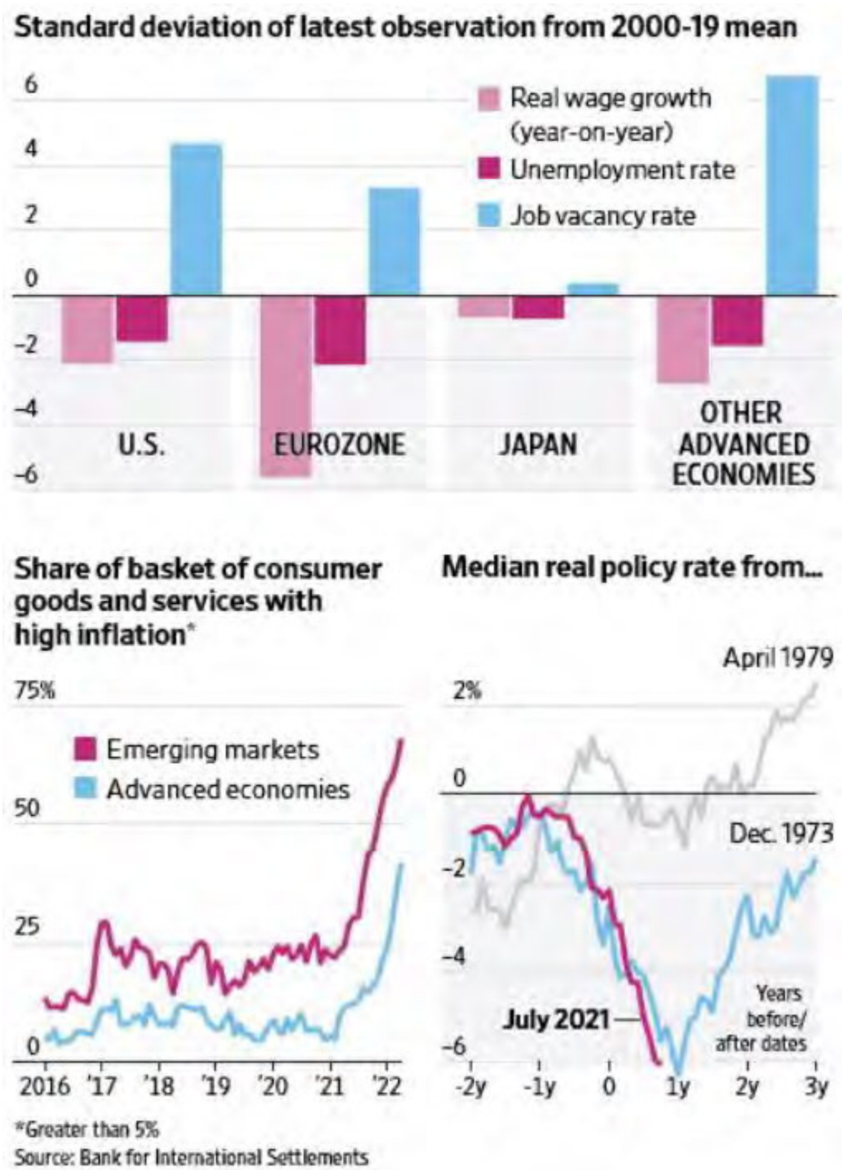
BIS Warns Rates Must Rise Faster

by Tom Fairless – WSJ, Outlook Column – Jun. 27, 2022

From Sydney to Washington to Zurich, **major central banks** have **stepped up** the pace of **interest-rate increases** in recent weeks, reflecting concerns that inflation isn't retreating as expected.

It might not be enough.

The world's central banks must raise interest rates sharply, even if it significantly hurts growth, the institution known as the **central banks' central bank warned** on Sunday. If they don't, the world risks a **1970s-style inflationary spiral**, the Bank for Inter-national Settlements said in its annual report. Even if they do, the global economy could face a toxic combination of low or negative growth and high inflation, known as **stagflation**, it said.



The **Federal Reserve** **this month increased** its policy rate by **0.75 percentage point** to a range between 1.5% and 1.75%, but it is still deeply negative in real terms, i.e. after adjusting for inflation. Central banks in Australia, Canada, New Zealand, Switzerland and Norway have recently announced 0.5-percentage-point rises in interest rates, but their real policy rates remain far below zero.

"**Gradually raising** policy **rates** at a pace that **falls short** of **inflation increases means falling real interest rates**. This is hard to reconcile with the need to keep inflation risks in check," the **BIS said**. "Given the extent of the inflationary pressure unleashed over the past year, real policy rates will need to increase significantly in order to moderate demand." Inflation erodes the value of money. If the interest rate is below the inflation rate, debtors pay back less than they borrowed, measured in terms of what that money can buy. That encourages people to borrow.

The **Switzerland-based BIS**, which **acts as** a **bank and think tank for central banks**, drew uncomfortable parallels with the 1970s. Then, as now, real policy rates fell far below zero, meaning central banks were stimulating rather than slowing economic activity as inflation surged.

Adding to the **risks**: **Over-valued assets** and **high debt**, which were much less of a concern in the 1970s, **could magnify any growth slowdown**. “A modest slowdown may not be enough. **Lowering inflation could involve significant output costs**, as after the ‘Great Inflation’ of the 1970s,” the BIS wrote.

The **BIS** has **issued** a series of **warnings** in **recent years about** an **overreliance on easy money**, but its advice went largely unheeded.

There are differences from the 1970s, too. Recent commodity- price rises are proportionally smaller, though spread across a broader range of goods, and commodity supply has so far held up better, the BIS said. Major central banks are now independent of governments and have a clear mandate to keep inflation at 2%, neither of which was true in the 1970s. Back then, Fed Chairman Arthur Burns was late to raise interest rates after coming under pressure from President Richard Nixon to keep unemployment low ahead of the 1972 presidential election.

Even so, the path of real rates in advanced economies over the past 12 months bears a striking resemblance to the 1970s, with large declines ahead of an oil-price shock, the BIS said. In most advanced economies, real rates are between 1 and 6 percentage points below their historical range over the past three decades, it said. “At this stage, it’s too early to say that the task [of central banks] has been completed,” Agustin Carstens, general manager of the BIS, told reporters.

Earlier this month, **Fed** officials **signaled** they **expect** to **raise their policy rate to between 3.5% and 4% next year**. That would be a positive real rate if inflation returns to the Fed’s target of 2%, but negative if instead inflation stays closer to current levels. They expect the unemployment rate to rise slightly, from 3.6% now to 4.1% in 2024. That scenario avoids a recession, though Chairman Jerome Powell told lawmakers this past week that a recession is possible.

The European Central Bank has signaled a gradual series of rate increases from the current level of minus 0.5%. Speaking to European lawmakers this month, ECB President Christine Lagarde said the bank planned to increase rates to more normal levels, but not higher. “We certainly are not tightening monetary policy,” Ms. Lagarde said. The ECB expects both unemployment and inflation to decline.

Given that inflation has spread to a broad variety of goods and services, such gentle policy moves are unlikely to work, said Stephen Cecchetti, a former senior BIS official who is now a finance professor at Brandeis International Business School. He estimates U.S. unemployment will likely need to reach 5% for several years to bring inflation down. “The question is whether you can drive it all out in one recession, or if it could take more than one recession,” Mr. Cecchetti said.

Another challenge: The longer high inflation persists, the more likely it is to remain high. People tend to ignore price increases when inflation is low but start paying more attention when it is high, and changing their behavior in response. Workers who have lost purchasing power seek larger wage rises.

In the **U.S., wages** are **rising** at an **annual rate** of about **6.1%,** according to the **Fed**eral Reserve Bank of **Atlanta**. In **Europe**, **wages** are likely to be **rising** at an annual rate **of 5%** by year end, a pace that could be sustained through the end of 2023, according to economists at Deutsche Bank.

“We may be reaching a **tipping point**, **beyond which** an **inflationary psychology spreads** and **becomes entrenched**,” the **BIS wrote**. “This would mean a **major paradigm shift**.”

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Buffett-Backed BYD Climbs Ranks of Chinese Car Makers

by Selina Cheng – WSJ – Jul. 26, 2022

As sales of most major auto makers in China have sunk this year, hit by rigid Covid-19 lockdowns and supply-chain disruptions, a **Warren Buffett-backed Chinese car maker** has **zoomed past rivals**, rapidly nearing the top position.

Left: Auto-show attendees check out BYD.

BYD Co., which stands for "**Build Your Dreams**," is a source of national pride to many in China and has enjoyed success overseas. **In** the **U.S.**, it is better **known** as an **electric-bus maker**, where buses produced by its Lancaster plant in California are on roads everywhere from Los Angeles to Denver.

As China was dealing with Covid outbreaks, **BYD became** the **second-best-selling brand in** its **home market** – after Volkswagen AG's joint venture with state-owned FAW Group Co. – for the first half of the year. That is a remarkable ascent given it didn't rank among the top 15 a year earlier. Its car sales more than doubled in that period compared with a year ago, while the overall market dropped by 7.2%, data from the China Passenger Car Association showed. The value of its **shares listed** in **Shenzhen** has **grown** more than **30%** in the **past six months**.

BYD, which stopped making traditional combustion-engine cars in March, is emerging as a formidable rival to Tesla Inc., the world's dominant electric-car maker. BYD sold around 324,000 electric vehicles globally between January and June, chasing Tesla's sales of about 565,000 vehicles. During that period, BYD also sold about 315,000 plug-in hybrid cars.

Driving its rapid acceleration is its business model of producing its own electric-car batteries and some semiconductors, helping it secure two of the most crucial components when rivals are grappling with supply-chain disruptions and chip shortages. It also allows BYD to control costs.

BYD has "much more control over their own destiny" than other car makers because of that business model, said Tu Le, managing director for consulting firm Sino Auto Insights.

While **BYD** as a car maker **competes** with Tesla and other brands, it **also serves as** a **supplier** to some of them, creating a **rival-partner dynamic** at times.

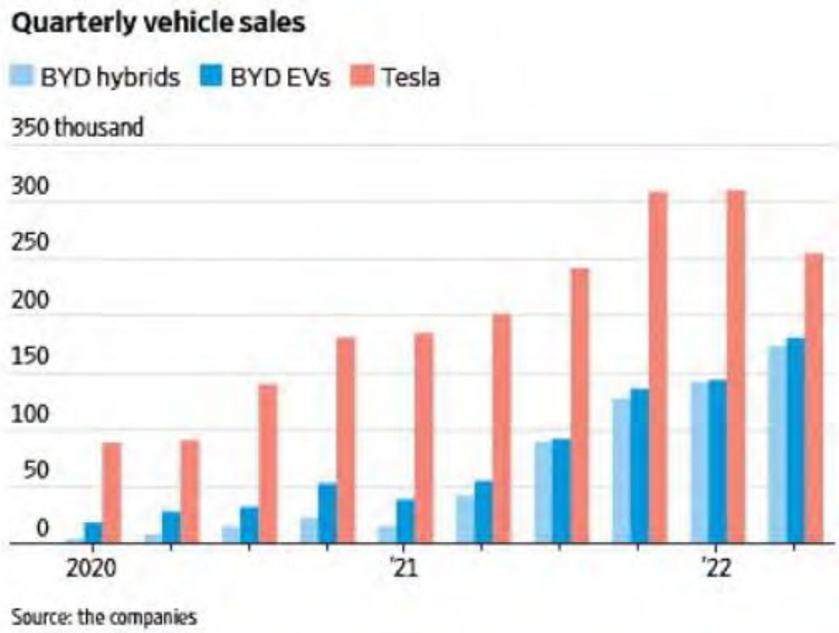
BYD was relatively unscathed by Covid-related city lockdowns that struck some rivals hard. Two of China's biggest automotive hubs – Shanghai, in eastern China and Changchun in the north – went through rigid lockdowns in the spring, forcing auto makers including Tesla, Volkswagen and Toyota Motor Corp. to halt production at their plants in those cities. Other auto makers reliant on components produced in those areas also struggled as production and deliveries were disrupted. But the southern city of Shenzhen and central China, continued churning out cars. For one month, in April, as Shanghai was locked down, BYD emerged as China's bestselling brand. In that month, Tesla, whose plant in Shanghai halted production in the middle of the lockdown, delivered 1,512 cars in total – a tiny fraction of the tens of thousands it usually sells each month.

A spokeswoman said BYD would continue to pursue having a strategic presence throughout the supply chain.

Chinese homegrown auto brands have consistently outperformed rivals with foreign joint ventures. Homegrown brands saw sales rise 18% in the first half of this year compared with the same period in 2021. Joint-venture brands saw sales fall 6%, according to data from the China Passenger Car Association.

BYD began as a **rechargeable- battery maker in 1995, developing into a major supplier of mobile-phone batteries** over the next decade. It also made some chips used in mobile phones. In **2003**, it **acquired** a **small state-owned auto maker**, establishing itself as a privately run Chinese car maker.

In **2008**, Mr. Buffett's **Berkshire Hathaway** invested $230 million for a **10% stake** in **BYD**. The stake recently amounted to about 7.7% of the company, according to Berkshire Hathaway's 2021 annual report. The company's market capitalization had grown to $126 billion as of Saturday.


Quarterly vehicle sales
BYD hybrids
BYD EVs
Tesla
350 thousand
300
250
200
150
100
50
0
2020
'21
'22
Source: the companies

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Companies' Capital Spending Ramps Up, Buoying Investors

by Hannah Miao – WSJ – Aug. 5, 2022

The **biggest U.S. companies keep stepping up their spending on capital projects**, an encouraging signal to investors in an uncertain economic climate.

Companies from Google parent Alphabet Inc. to General Motors Co. to PepsiCo Inc. are among those that have increased spending on big-ticket items, such as real estate, equipment or technology, to fuel growth. The investments are generally intended to expand the companies' fast-growing operations or even optimize their inventory in the midst of a challenging business environment, executives say.

Capital expenditures among companies in the S&P 500 have been growing at a **faster pace than stock repurchases** for the first time since the first quarter of 2021, according to data analyzed by S& P Dow Jones Indices from the second-quarter earnings season.

Based on results from roughly three-quarters of the companies in the index, **capital expenditures have risen 21% from** a **year earlier** to $165.5 billion, roughly in line with the first quarter's growth rate. **Meanwhile, share repurchases have climbed 14%** to $175.5 billion and **dividends** have **increased 14%** to $140.6 billion.

The spending boom has offered a leg of support to a stock market that has been buffeted by worries about soaring inflation and the pace of the Federal Reserve's campaign to raise interest rates. The S&P 500 has slumped 13% this year but has rebounded 13% from its low in mid-June.

"One reason that stocks haven't absolutely fallen off a cliff right now is because of that increased capex," said Ben Silverman, director of research at investment research firm VerityData. "There's signaling from the executive suite that they're comfortable spending money instead of hoarding cash."

The latest round of corporate earnings reports have offered **conflicting views** about the **economy's trajectory and whether** a **recession** is **on** the **horizon**.

Inflationary pressures have driven up the **costs** of **everything from food to fuel and raw materials**, **weighing on corporate profit** and **weakening consumers' buying power**.

Investors continue to parse mixed data about the health of the economy. **Gross domestic product** has **contracted** for **two straight quarters**, a common definition of a recession. **Still, job gains remain strong**, and the **unemployment rate** is **holding steady**. Investors are awaiting the latest reading on the labor market with July's jobs report due on Friday.

Meanwhile, Wall Street sentiment hit its lowest level in more than five years in July, according to Bank of America's latest reading of sell-side strategists released this week. Extreme bearish sentiment is often a contrarian signal for a potential rally, the bank's analysts said.

Companies in the information- technology, communications- services and industrials sectors have been the biggest contributors to capital-expenditure growth, according to a Bank of America analysis.

Alphabet, for one, reported last week that its second-quarter capital spending rose to $6.8 billion, up from $5.5 billion a year prior. The company said it is spending on technical infrastructure, particularly servers.

"With an uncertain global economic outlook, our strategy to invest in deep technology and computer science to build helpful products for the long term is the right one," Chief Executive Sundar Pichai said on the company's earnings call.

Likewise, GM's capital spending climbed to $2.1 billion in the second quarter from $1.5 billion in the same period a year before. Chief Financial Officer Paul Jacobson, on GM's earnings call, highlighted the auto maker's push to expand its electric-vehicle fleet. "The investments we have made in these vehicles over the last couple of years…provide a strong bridge to our all-electric future," he said.

PepsiCo finance chief Hugh Johnston pointed to digital investments to ensure stores are stocked with appropriate inventory as the beverage-and-snack company reported $1.5 billion in capital spending in the 24 weeks ended in mid-June, up from $1.3 billion during that period a year prior.

"If we have a series of earnings here where capital expenditures continue to be quite strong and companies are willing to spend that capital, that means they're giving a pretty optimistic outlook for their business," said Victoria Fernandez, chief market strategist and portfolio manager at Crossmark Global Investments.

Some of the growth in capital spending can be attributed to a restart in typical behavior after companies chose to stockpile cash during the depths of the Covid-19 pandemic.

Companies in the **S& P 500 held** about **$1.667 trillion** in **cash and equivalents** on their balance sheets at the **end** of the **first quarter**, **down from $1.797 trillion** at the

end of **2021**, according to S& P Dow Jones Indices. That figure excludes the financial, real-estate, utilities and transportation sectors because those companies normally maintain high cash reserves. Other companies are spending to bring production to the U.S. to stem supply-chain challenges that have led to shipping delays and shortages of key products such as chips. Mentions of "**reshoring**" during earnings conference calls have skyrocketed in 2022, according to Bank of America.

"That's going to be a longer- term theme that reflects the reality that there's a compelling opportunity to … manufacture and build in America," said Rajesh Nakadi, head of investments at BNY Mellon Wealth Management Global Family Office.

Some companies are tightening their belts. Intel Corp. last week cut its capital-spending forecast for the year. The chip maker reported a surprise quarterly loss and its biggest revenue decline in more than a decade, blaming a slump in personal-computer purchases and product delays.

Companies are **still keeping plenty of cash on** the **sidelines**, signaling some restraint in capital spending, said Howard Silverblatt, senior index analyst at S& P Dow Jones Indices.

"Is it a record?" asked Mr. Silverblatt of capital expenditures. "No, but they are good numbers. It's definitely an up quarter despite concerns."

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Consumers Can Say 'No' to Gas Prices

by Justin Lahart and Jinjoo Lee – WSJ – Jul. 19, 2022

One of the things that makes **high gasoline prices** so difficult for families is that, unlike something like a TV that has shot up in price, they have **no option but to pay.**

But **with** the **increased** ability to **work from home** the pandemic has brought on, that **isn't as true as** it was **in** the **past**. Although the evidence is preliminary, it looks as if many **Americans** might have **responded to** the **jump in gasoline prices by reducing trips to work**. It is a development that could have far-reaching repercussions that softens price volatility, pushing people's gasoline bills lower than they otherwise would have been while putting a cap on oil producers' and refiners' sky-high margins.

Most Americans drive to work, and the expense adds up: **Commuting- fuel use accounts** for around **30%** of **gasoline consumption**, according to a report from Federal Reserve Bank of Dallas economist Garrett Golding. Moreover, while people have always had some flexibility when it comes to their commutes – they can start carpooling or learn the local bus route—in the short run the options are limited. That is a big reason **gasoline prices** are considered **relatively inelastic** versus many **other items**: **When prices go up**, **demand goes down** only so much.

But many workers' newfound ability to work from home at least some of the time changes the equation. When pump prices seem onerous, somebody who has been driving to work three days a week could decide to go in for just two days, for example. That might be happening. A census survey conducted over the 13 days ended April 11, when regular gasoline averaged about $4.13 a gallon, showed an estimated 67.3 million people worked from home at least once a week. In a survey conducted over the 13 days ended June 13, when a gallon averaged $4.94, the estimated number of people working from home at least once rose to 69.7 million.

Over the four weeks ended July 8, implied motor-gasoline demand averaged 8.7 million barrels a day, down 8% from the same period last year, according to data from the U. S. Energy Information Administration. Three months earlier, implied gasoline demand had been just 2.3% below year-earlier levels.

Finally, it looks as if **people are driving less**. Data from the California Department of Transportation show the total number of miles traveled on California highways on weekday mornings in June, excluding truck traffic, was down 0.5% from a year earlier. That decline is particularly notable considering that, as of May, employment in California was 5.4% higher than in June of last year.

Of course it is difficult to pinpoint exactly how much of the commuting decline is due to more people getting sick from **Covid-19** versus those who are **experiencing** sticker shock from fuel prices. The **latest variant** – **BA.5** – is **highly contagious**, and more **than 100,000 new Covid-19 cases** are being **reported each day**. The actual number could be much higher since many people test at home. Data from Kastle

Systems shows that office occupancy has recovered in fits and starts since the nadir seen in April 2020, with large dips corresponding to waves of Covid-19.

Nevertheless, Christopher Knittel, a Massachusetts Institute of Technology economist who has conducted research on consumer responses to gasoline-price changes, thinks the **option to work from home** has probably **led to more price elasticity**. That should reduce price volatility and, all else being equal, lowers prices as well.

"It's not much consolation for people paying $5 now, but what it tells us is the price spike would have been even higher," he says.

At the same time, consumers generally seem to have become more sensitive to gasoline prices, says energy economist Philip Verleger. He calculates that before 2000, spending on motor fuels as a share of total consumer spending almost doubled when gasoline prices doubled. In recent years, that effect has been halved such that a doubling of gasoline prices would yield just a 50% increase in motor-fuels spending. For oil producers and refiners, more price-sensitive consumers could affect their investment plans. Many are already baking in a lot of caution.

The oil market historically had both inelastic supply and demand. In much the way fracking was the technological revolution that made it possible for oil supply to be more elastic, the adoption of **hybrid work** today **could radically change** the **equation for demand**.

Before 2000, a doubling of gasoline prices meant spending on motor fuels (as a share of total consumer spending) almost doubled

Note: Relative gasoline price is indexed to 2012 price
Source: PKVerleger analysis of Bureau of Economic Analysis data

Decline In Prices for Raw Materials Buoys Investors

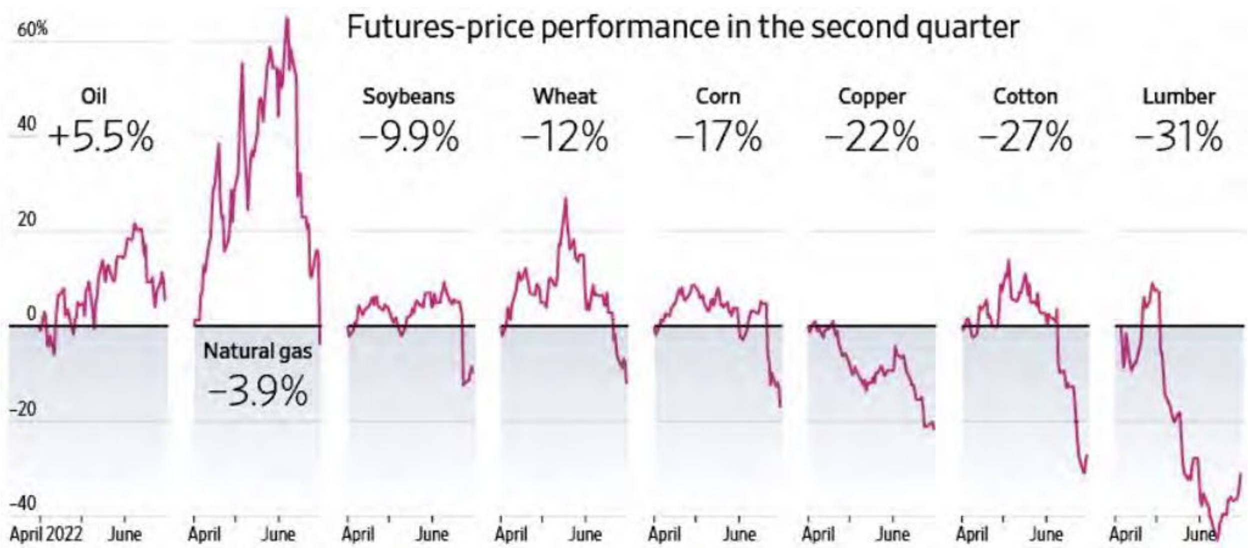
by Ryan Dezember – WSJ – Jul. 5, 2022

A tumultuous quarter ends for commodities, offering a glimmer of hope inflation could ebb.

Natural-gas price drop 3.9% after more than 60% rise in quarter.

A **slide** in **all manner of raw-materials prices—corn**, **wheat**, **copper** and more – is stirring hopes that a significant source of inflationary pressure might be starting to ease.

Natural-gas prices shot up more than **60% before falling back** to **close** the **quarter 3.9% lower**. **U.S. crude slipped from** highs above **$120 a barrel to end** around **$106**. **Wheat**, **corn** and **soybeans** all wound up **cheaper than** they were **at** the **end of March**. **Cotton unraveled**, **losing** more than a **third** of its **price** since early May. Benchmark prices for building materials **copper and lumber dropped 22% and 31%, respectively**, while a basket of industrial metals that trade in London had its worst quarter since the 2008 financial crisis.



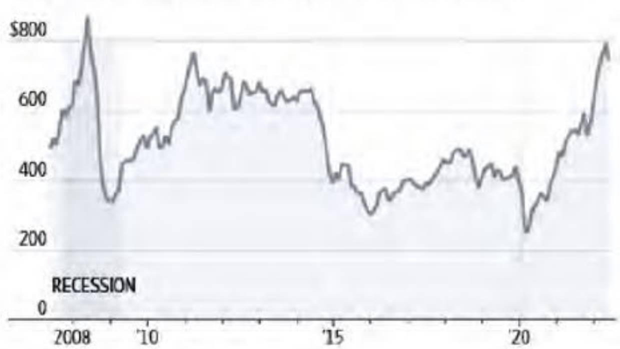
Many raw materials remain historically high-priced, to be sure. And there are matters of supply and demand behind the declines, from a fire at a Texas gas-export terminal to better crop-growing weather. Yet some investors are starting to view the reversals as a sign that the Federal Reserve's efforts to slow the economy are reducing demand.

"Moderating commodity prices are clear evidence that inflation is cooling," said Louis Navellier, chief investment officer at Reno, Nev., money manager Navellier & Associates.

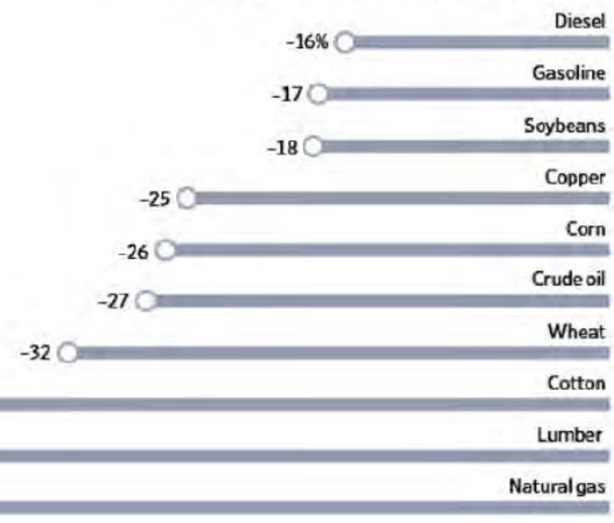
Commodities have garnered extra interest on Wall Street, where investors are eyeing volatile raw-material markets to gauge inflation and have been investing in them to counteract the effect of rising prices on the rest of their portfolios.

Shares of commodity firms were among the few havens for investors during stocks' worst first half in decades. **Though** they have **slumped from highs** notched earlier in the quarter, **oil producers Exxon** Mobil Corp. and **Occidental** Petroleum Corp. **ended** the first half **up 40% and 103%, respectively**. **Fertilizer** maker **Mosaic** Co. **gained 20%**. Grain trader **A**rcher **D**aniels **M**idland Co. **added 15%.**

S&P GSCI commodity index, monthly



Percentage off of record prices*



*Continuous most-active futures contracts as of June 30
Source: FactSet

Investors plan this week to parse minutes from the Fed's June 14-15 meeting, which are scheduled to be released Wednesday, seeking clues about the pace of interest-rate increases for the remainder of the year. The Fed is trying to tame the highest inflation since the early 1980s by reducing demand without tipping the economy into recession.

Traders and analysts said that some of the decline in commodity prices can be traced to the retreat of investors who piled into markets for fuel, metals and crops to hedge against inflation. J P-Morgan Chase & Co. commodity strategist Tracey Allen said about $15 billion moved out of commodity futures markets during the week ended June 24.

It was the fourth straight week of outflows and brought to about **$125 billion** the total that has been **pulled from commodities this year**, a seasonal record that tops even the exodus in 2020 as economies closed.

"I don't know if the **policies** of the **Fed** have **slowed** the **economy**, but that's what money managers are betting on," said Craig Turner, commodities broker at StoneX Group Inc.

Much of the climb in prices was due to supply constraints following **pandemic lockdowns**, **weather events** last year that reduced harvests and sapped fuel reserves, and **war in Europe**. Those pressures have eased, though supply shocks are still jolting prices.

The **E**nergy **I**nformation **A**dministration said last week that **U.S. oil output averaged 12.1 million barrels a day** during the week ended June 24, the most since April 2020 when the economy was locking down and producers were shutting in wells.

Damage from a **fire** last month at **one** of the **country's largest exporters** of **liquefied natural gas** has **left more** of the **power-generation fuel** and **manufacturing feedstock for** the **domestic market** and **eased fears of winter shortages**.

Natural-gas inventories in the **Lower 48 states** are **12.5% below** the **five-year average for** this **time of year**, **down from** a deficit of roughly **17% in March**, the EIA said.

Improved growing weather in the **U.S., Europe** and **Australia** is raising hopes that bumper crops can make up for the wheat, corn and vegetable oil stranded in **Ukraine** since **Russia** invaded. **Grain and oilseed prices shot up after** the **incursion but have fallen back to** or below where they were **before** the **late-February attack**.

Higher mortgage rates have **cooled** the **market for new homes** and popped the pandemic lumber bubble. Mean-while, **coronavirus lockdowns** in **China** and a **shift** in **U.S. consumer spending from goods to services**, such as **travel** and **entertainment**, have **dimmed** the **outlook** for **cotton and copper demand**.

Despite the pullbacks, some still see commodities as a safe bet amid a bad year for stocks and bonds.

JPMorgan analysts said inventories around the world remain low and suggest buying agricultural futures. They expect a basket of commodities to return 10% by the end of summer and 5% by yearend.

Mr. Navellier said he is holding shares of oil drillers, shippers, fertilizer makers and chicken producers. "I know **prices** have peaked, but prices are **elevated**," he said. "I'm going into second-quarter earnings locked and loaded."

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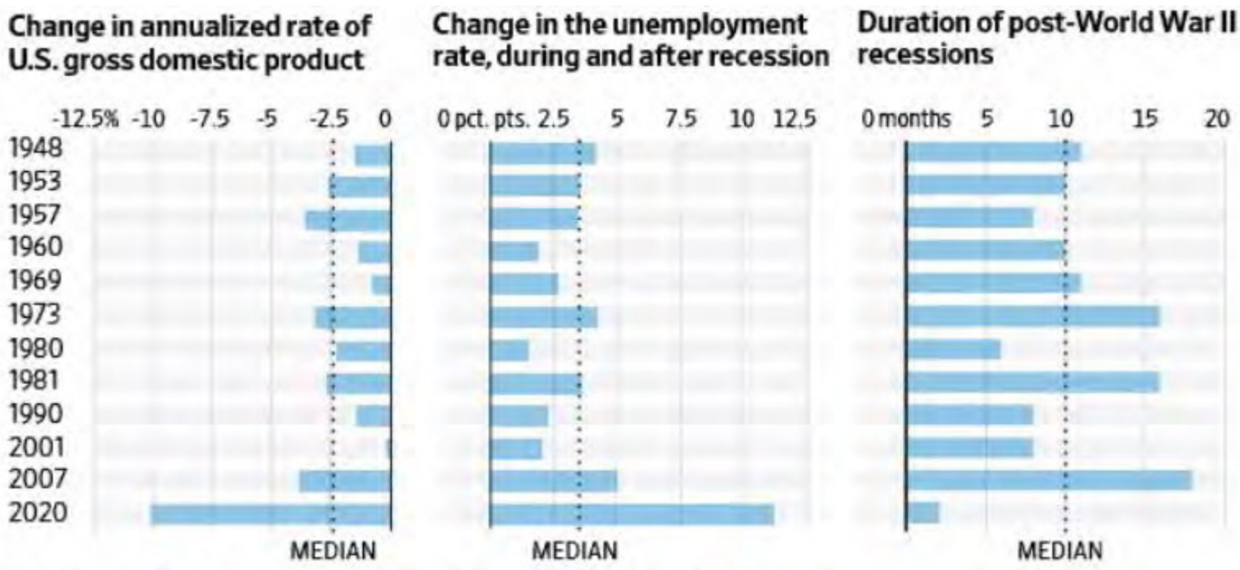
If the U.S. Is in a Recession, It's a Very Strange One

by Jon Hilsenrath – WSJ – Jul. 5, 2022
Anthony DeBarros contributed to this article.

Economic output is down, **but** the **job market** is **strong.**

The **U.S. economy** has experienced **12 recessions since World War II**, and **each** one included **two features**: **Economic output contracted** and **unemployment rose**.



Note: Recessions listed by year they began, from trough to peak for GDP and unemployment rate.
Source: Bureau of Economic Analysis

Today, something highly unusual is happening. Economic output fell in the first quarter and signs suggest it did so again in the second. Yet the job market showed little sign of faltering during the first half of the year. The jobless rate fell from 4% last December to 3.6% in May.

It is the latest strange twist in the odd trajectory of the pandemic economy, and a riddle for those contemplating a recession. If the U.S. is in or near one, it doesn't yet look like any other on record.

Analysts sometimes talked about "jobless recoveries" after past recessions, in which economic output rose but employers kept shedding workers. The first half of 2022 was the mirror image – a "jobful" downturn, in which output fell and companies kept hiring. Whether it will spiral into a fuller and deeper recession isn't known, though a growing number of economists believe it will.

Some companies, especially in the tech sector, have given indications that they're pulling back on hiring, though across the broad economy the job market has rarely looked stronger.

At the end of June, 1.3 million Americans were collecting federal unemployment checks, substantially fewer than the 1.7 million people collecting them on average each week during the three years before the pandemic, when the economy was considered to be exceptionally strong. The number of people receiving such benefits topped 6.5 million during the 2007-09 recession and exceeded 3 million during the two earlier downturns.

"I would be surprised if there were a recession without much job loss," said Gregory Mankiw, a Harvard University economics professor. He said if one is coming, it would likely be provoked by Federal Reserve interest rate increases. A "small downturn" could be needed to bring inflation under control, he said.

Recession indicators

The official arbiter of U.S. recessions is the **National Bureau** of **Economic Research**, a collection of mostly academic economists who place dates on when recessions begin and end, going back to 1857, the first U.S. recession on record. Mr. Mankiw served on the committee during the 1990s.

One popular rule of thumb is that the **economy is in recession when gross domestic product** – a measure of the nation's output of goods and services – **contracts for two consecutive quarters**, **but** that's not the way the **NBER** sees it. Its eight-member business cycle dating committee **looks** at a range of monthly and quarterly **indicators**, including output, income, manufacturing activity, business sales and, perhaps most important, employment levels. Then it **makes** a **judgment call**.

"A recession is a significant decline in economic activity spread across the economy, normally visible in production, employment, and other indicators," the committee says.

The indicators don't always move in sync. In 2001, output didn't decline much, and GDP didn't contract for two consecutive quarters, but the NBER called it a recession, anyway. In 1960, inflation-adjusted household income rose, and that was a recession, too.

One common denominator has been jobs. The unemployment rate has increased every time, by as little as 1.9 percentage points in 1960 and 1961 and as much as 11.2 percentage points in 2020. The median increase in the jobless rate among all 12 post-World War II recessions was 3.5 percentage points. The U.S. didn't escape any of those recessions with a jobless rate below 6.1%.

Monthly business payrolls, watched closely by the NBER, also have fallen in every recession, by about 3% in a typical one. Yet between December and May, payrolls rose 2.4million, or 1.6%. They are a coincident indicator, meaning they tend to rise and fall in sync with broad economic activity.

On Friday the Labor Department will report nationwide figures for payrolls and unemployment for June, a potentially critical moment in the recession debate. Economists surveyed by The Wall Street Journal in advance of the report said they expected the Labor Department to report that the jobless rate held steady at 3.6% last month and payrolls kept expanding.

The backdrop to U.S. jobs is now unusual. The **U.S.** has recorded more than **11 million unfilled job openings** in **six of** the **past seven months**, four million more monthly openings than was typical before Covid-19 hit the economy in early 2020. In other words, demand for workers is abundant.

At the same time, **labor is scarce** – in part because **baby boomers are retiring**—making firms reluctant to fire the workers they have. The size of the **labor force**, at **164.4 million** in **May**, was still slightly smaller than the 164.6 million people who were working or looking for work right before the pandemic, so even when people do lose work, there have been many unfilled positions available.

Robert Gordon, a North-western University economics professor and member of the NBER's business cycle dating committee, said this might be a situation in which other indicators point to recession but the job market doesn't, or it lags behind atypically for several months.

"We are going to have a very unusual conflict between the employment numbers and the output numbers for a while," he said. Some other meaningful indicators, such as manufacturing and wholesaler sales, have also weakened, he added, making him wary that a recession is near. He noted he wasn't speaking for the committee or any decisions itmight make.

Looking ahead

Even the most pessimistic economists see a modest jobs downturn in the months ahead.

About two in five economists surveyed by the Journal in June said they saw at least a 50-50 chance that the U.S. enters recession in the coming year, but among them, few saw a big increase in the jobless rate. They forecast a 3.9% unemployment rate at the end of this year and a 4.6% unemployment rate at the end of 2023. The U.S. has never had a recession in the post-World War II era with a jobless rate that low.

"The U.S. is in, or on the precipice, of a shallow but yearlong recession. This will assist the Fed in its inflation fighting efforts," said Sean Snaith, director of the University of Central Florida's

Institute for Economic Forecasting, in the Journal's survey. He sees the jobless rate rising to 6% by the end of 2023, the only person in the survey who saw the rate reaching that level in the next 18 months.

History shows that recessions come in many forms.

Some downturns have been long and deep, such as the downturn of 2007-09 that sent the unemployment rate to 10%; others short and shallow, such as the 2001 recession that lasted eight months. Others were part of serial downturns, as happened in the 1950s and 1980s, when recessions came in succession, a short time apart.

"Each recession seems to have a different driving force and different duration and impact on jobs and output," said Peter Klenow, a Stanford University economics professor. "I think of the 1980 recession as Carter credit controls, 1981-1982 as the Volcker recession, 1990-1991 as a credit crunch, 2001 the bursting of the dot-com bubble, 2008-2009 the global financial crisis, and 2020 the pandemic recession."

The 2020 recession, in particular, was unlike anything recorded in U.S. history, exceptionally short at just two months, and exceptionally severe. Companies cut 22 million jobs in those two months, 14 times more than they had ever cut in a two-month period during the post-Depression era.

This was a precursor to the turbulence still hitting the economy more than two years later.

Officials reacted to the Covid shock by flooding the economy with **stimulus** and **boosting demand**. **Supply chains broke down**, in part because of **Covid-related business closures**. The surge of demand and collapse of supply then bred higher inflation. The Fed is now trying to slow it by **raising short-term interest rates** to restrain demand for interest-sensitive spending, such as on cars, homes and business projects.

What happened in the first part of the year in part reflected volatility in the economy that followed Covid, compounded by **Russia's invasion** of **Ukraine**. Businesses drew down inventories in the first quarter after building them up in 2021, according to Commerce Department data. The **U.S. trade position** also deteriorated, meaning **fewer exports** and **more imports**.

The inventory reductions were central to a contraction in gross domestic product at a 1.6% annual rate in the first quarter. Rather than build new cars or computer chips, companies took them off their own shelves.

A **Federal Reserve Bank of Atlanta** model closely watched on Wall Street estimates that **economic output contracted** again in the **second quarter**, at a 2.1% annual rate. The model puts inventory reductions as the biggest downward weight on output.

Inventories are a business buffer for surprises, and cycles of inventory building and destocking have been common ingredients in the early stages of past recessions. Firms at times produce too much in anticipation of demand and then have to pull back when the demand doesn't materialize. In past cycles, production declines associated with inventory reductions set off a series of events that caused recessions, including layoffs, household income loss and then slowing consumer spending.

New risks

One risk now is that inventory cutting leads to wider business retrenchment that feeds on itself, as happened in some past recessions.

Another uncertainty is the outlook for home building, which is highly interest rate sensitive and has been another leading indicator during past downturns. **New-home**

construction dropped 14% in **May** from a month earlier, seasonally adjusted, a drag that could persist as the Fed raises short-term interest rates.

Most post-World War II recessions have been associated with declines in residential home construction, though the hit this time may not be severe because building wasn't as overheated in recent years as it had been in the past. In the first quarter, total U.S. spending on home-building was still 22% below the pace of building at the peak of the housing boom of the early 2000s, according to Commerce Department data.

Bruce Kasman, chief economist at J.P. Morgan, predicts a "bend-but-don't-break" scenario for the economy, meaning a sharp slowdown in activity that doesn't crack the job market. However, he adds that he doesn't have great conviction about that prediction, given the unusual backdrop and the shocks that keep hitting the economy.

Though corporate profits are slowing, he said, corporate profit margins are exceptionally high, historically. At around 18% of sales during the past year, after-tax profits have rarely been higher in post-World War II history. Heading into recessions in 1991 and 2001, firm profit margins had fallen to single digit levels. Firms cut back on spending to build profits, and dragged the economy down in the process.

Mr. Kasman said firms now have a large cushion to the growing profit slowdown. **Businesses** are also **swimming** in nearly **$4 trillion** of **cash**, a record, he said.

Slow growth and continued hiring would add up to productivity and profit pressures for many businesses. That would be bad news for stocks, he said. But a recession? He's not counting on it.

Households are **flush with cash**, too. At the end of the first quarter, they had **$18.5 trillion** in **checking accounts**, **savings accounts** and **money market mutual funds**, according to Fed data. That was **up from $13.3 trillion before** the **pandemic**, boosted in part by **several rounds** of **relief checks** sent to households in the past two years.

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Powell's Remarks Send Treasury Yields Lower

by Matt Grossman – WSJ – Jul. 28, 2022

Short-term government-bond yields declined Wednesday afternoon after the **Fed**eral Reserve **raised interest rates by 0.75 percentage point** at its July meeting.

Most investors considered the **Fed's rate increase**, which brought its target **to** a **range of 2.25% to 2.5%**, a **foregone conclusion**. **But Treasury yields fell as Chairman Jerome Powell** spoke to reporters after the meeting, with some traders perceiving leeway in his **remarks** for a **less aggressive series** of **rate increases to follow**.

Through the market's 3 p.m. settlement, the **yield** on the **10-year Treasury note fell** to **2.731%, from 2.786%** on **Tuesday**, according to Tradeweb. The **two-year yield**, which is even **more sensitive to expected Fed policy**, **fell to 2.968%, from 3.041%** a day earlier. Bond yields fall as bond prices rise.

As Mr. Powell continued speaking, later-afternoon trading exacerbated the two-year yield's larger decline. Investors said that pattern showed a slide toward expectations of a more moderate pace of Fed rate increases ahead.

"I think the market was still open to the possibility that Powell would come out with both barrels to suggest the Fed was going to need to maintain an aggressive posture," said Cindy Beaulieu, a managing director at asset manager Conning. "We didn't get that."

In the news conference that followed the Fed meeting, Mr. Powell reiterated the central bank's commitment to taming **inflation** that, at **9.1%, reached** its fastest **pace last month in more than 40 years**. The Fed's latest rate increase is this year's fourth, following a same-size increase in June that was the Fed's most aggressive rate move since the 1990s.

Mr. Powell also acknowledged signs that the economy is slowing, noting signs of pressure on consumer spending, industrial production and the housing market, although he told reporters that he doesn't think the economy is currently in a recession.

Wednesday's trading after the news conference diminished a pattern known as a yield-curve inversion – when short-term yields are higher than long-term yields. Many investors take inversions as a worrying economic sign, because lower long-term rates signal that traders think the Fed will eventually need to pivot to interest-rate cuts as economic output slows or contracts.

By the time Mr. Powell had finished speaking to reporters, the yield curve was less inverted than it was earlier in the day. That suggests traders were giving more credence to the possibility of a soft landing for the economy, said Natalie Trevithick, head of investment-grade credit at Payden & Rygel.

"The faster the economy slows or shows signs of slowing down, the easier the Fed can be and the less deep the recession can be," she said.

Some analysts said the market's reaction to the Fed meeting underestimated how aggressive the Fed will continue to be, especially as monthly inflation data hasn't yet turned lower.

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Fed Chief Says Rate Increases Risk a Recession

by Nick Timiraos – WSJ – Jun. 23, 2022

Bringing down prices is ‘absolutely essential,’ Powell tells lawmakers at Capitol Hill hearing

Federal Reserve Chairman Jerome Powell said the **central bank’s battle against inflation could** lead it to raise interest rates high enough to **cause** a **recession**, offering his most explicit warning this year.

“It’s not our intended outcome at all, but it’s certainly a possibility,” Mr. Powell said Wednesday during the first of two days of congressional hearings. “We are not trying to provoke and do not think we will need to provoke a recession, but we do think it’s absolutely essential” to bring down **inflation**, which is **running at** a **40-year high**.

His remarks underscore the challenge facing the central bank as it raises interest rates at the most rapid clip since the 1980s to cool inflation.

The Dow Jones Industrial Average pared early losses after the release of Mr. Powell’s testimony on Wednesday morning but closed down 0.2%, or 47.12 points. The **yield** on the benchmark **10-year U.S. Treasury** note declined to **3.155%** from 3.304% Tuesday. **Yields fall when prices rise**.

Rising fuel costs and supply- chain disruptions from **Russia’s war against Ukraine sent prices up** in recent months. Those pressures **added to already-high inflation as demand surged last year** from the reopening of the economy and **aggressive government stimulus**.

The Fed is seeking to engineer a so-called soft landing by cooling the economy’s growth enough to lower inflation, but without causing a downturn.

During two hours of testimony on Wednesday and at news conference last week, Mr. Powell never mentioned a soft landing and only referred to it as a goal when he was asked about it.

“The events of the last few months around the world have made it more difficult for us to achieve what we want,” Mr. Powell told the Senate Banking Committee on Wednesday. Achieving the Fed’s 2% inflation goal with a strong labor market would be very challenging, he said. “We’ve never said it was going to be easy or straightforward.”

That marked a **notable change from** the **last time Mr. Powell appeared on Capitol Hill**, days after Russia’s invasion of Ukraine. “I think it’s more likely than not that we can achieve what we call a soft landing,” he told lawmakers on March 2.

Since then, the **Fed raised** its **federal-funds rate three times from near zero to** a **range between 1.5% and 1.75%**, **including** a **0.75-percentage-point rise last week**, the **largest in 28 years**. **Mr. Powell** and several colleagues **signaled** that **another increase** of **that magnitude** could be warranted at the Fed’s **July 26-27 meeting**.

"We're looking for…compelling evidence that inflation is coming down, and we don't have that," he said. "There are lots of stories out there about how this should happen, and some people think it's very clear that it will. Until we actually do see it happen, we need to keep moving."

Fed officials' new projections released last week showed **all 18 officials expected** to **raise** the **fed-funds rate to at least 3% this year**, with most seeing it rising to a range between 3.25% and 3.5% by December. That would exceed by 1 percentage point the highest level it reached after the 2008 financial crisis, in 2018.

The fed-funds rate, an overnight rate on loans between banks, influences borrowing costs throughout the economy, including rates on mortgages, credit cards and business loans. The Mortgage Bankers Association reported Wednesday that the average 30-year fixed mortgage rose to 5.98% last week, from 5.65% in the prior week, to the highest level since 2008. That was the largest one-week increase in mortgage rates since 2009.

The Fed drew criticism in recent weeks for not acting sooner to withdraw the aggressive stimulus measures it deployed last year. Mr. Powell, who was confirmed last month to a second term on an 80-19 vote by the Senate, faced sharp questioning from lawmakers on Wednesday.

Several Democrats warned Mr. Powell against raising rates too aggressively because they believed supply issues over which the Fed had little control were responsible for driving prices higher.

"You know what's worse than high inflation and low unemployment? It's high inflation and a recession with millions of people out of work," said Sen. Elizabeth Warren (D., Mass.). "And I hope you'll reconsider that before you drive this economy off a cliff."

In response to a similar concern from another Democratic senator, Mr. Powell volunteered that there could be a worse outcome than a recession. "The other risk, though, is that we would not manage to restore price stability, and that we would allow this high inflation to get entrenched in our economy," he said. "We can't fail on that task."

Republicans warned Mr. Powell against failing to take decisive action. "Clearly you are aware that you are going to be the person that takes the fall if inflation is not brought under control," Sen. Mike Rounds (R., S.D.) said.

Sen. Richard Shelby (R., Ala.) referred to concerns about high inflation that he raised with Mr. Powell at a hearing last summer. "I believe the Federal Reserve and this administration failed the American people by not heeding these warnings a year ago," he said.

The hearing didn't shed much light on difficult tradeoffs the central bank could confront in the next year, especially if its policy steps weaken the job market but don't bring down inflation in a convincing fashion.

A **new research paper** from a **senior Fed economist** published Tuesday found slightly more than a **50% chance** of a **recession over** the **next four quarters** and a **two-thirds probability** of a **downturn over** the **next two years**. Those probabilities are at levels last seen in mid-2019, when the Fed was shifting from raising rates to cutting them.

Mr. Powell said he didn't see the likelihood of recession "as particularly elevated right now." But he said, "You should know that no one is very good at forecasting recessions very far out."

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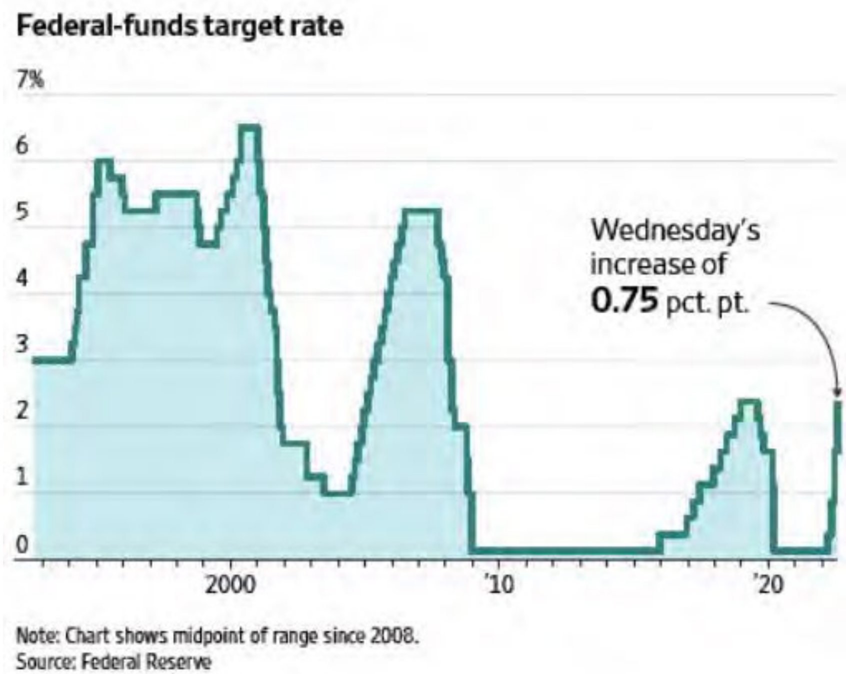
Fed Lifts Rates by 0.75 Point Again

by Nick Timiraos – WSJ – Jul. 28, 2022

Powell expects further increases even as some indicators show signs of softening. Mr. Powell cited brisk job growth in dismissing concerns of a recession.



The Federal Reserve continued a sprint to reverse its easy-money policies by approving on Wednesday another unusually large 0.75-percentage-point interest-rate increase and signaling more tightening was likely this year to combat 40-year-high inflation.

Officials agreed unanimously to lift their benchmark federal-funds rate to a range between 2.25% and 2.5%. Markets rallied after the meeting because Fed Chairman Jerome Powell offered fewer specifics about the magnitude of coming rate rises and hinted at an eventual slowdown.

The S&P 500 rose 2.6%, while the Nasdaq Composite had its biggest one-day percentage gain in more than two years, surging 4.1%. **Yields** on the benchmark **10-year Treasury note fell to 2.731%**.

Given Mr. Powell's insistence that the Fed has to cause slower growth and accept rising recession risks to bring down inflation, "it is a bit surprising that all assets reacted in such an exuberant manner," said Michael de Pass, global head of linear rates trading at Citadel Securities.

Mr. Powell said it was **too soon** to **say whether** the **Fed would dial down** the **size** of its **rate increases to** a **half or** even a **quarter point at** its **next meeting**, in September. But he said that at some point, it would be appropriate to slow the pace of rate increases to assess their cumulative impact on the economy.

"These rate hikes have been large, and they've come quickly," Mr. Powell said, referring to the Fed's four consecutive rate hikes since March. "And it's likely that their full effect has not been felt by the economy, so there's probably some significant additional tightening in the pipeline."

The Fed chairman said the slowdown in economic growth in the second quarter had been notable, citing signs of cooling consumer spending, hiring and housing activity. "Are we seeing the slowdown in economic activity that we think we need?" Mr. Powell said. "There is some evidence we are, at this time."

Mr. Powell suggested the central bank wasn't likely to ease up on rate increases simply because growth slows. That is because with inflation running well above the Fed's 2% target, it wants to see economic growth slow below its estimated long-term trend of around 1.8%.

"Not just tolerating below-trend growth but saying it's necessary now puts a different gloss on acknowledging the slowdown in spending and production," said Jeremy Schwartz, an economist at Credit Suisse.

The Commerce Department is set to report Thursday on U.S. gross domestic product, the broadest measure of goods and services produced across the nation, for the second quarter. Economists surveyed by The Wall Street Journal estimate GDP rose at a 0.3% annual rate.

Employers have been adding jobs at a brisk pace this year, and the unemployment rate has held at 3.6%, a historically very low level, between March and June.

The Labor Department is set to report Friday on a widely watched measure of wage growth that could be especially important to the Fed because it is trying to reduce households' purchasing power to slow inflation.

Mr. Powell cited brisk job growth in dismissing concerns that the economy is now in a recession. "I do not think the U.S. is currently in a recession," he said. "There are just too many areas of the economy that are performing too well."

Mr. Powell, who goes by Jay, repeated his view Wednesday that he is more concerned about the risk of failing to stamp out high inflation than about the possibility of raising rates too high and pushing the economy into a recession.

But some investors said Mr. Powell's delicate delivery of that message – he also said the Fed doesn't think a recession is necessary to bring down inflation – is undermining his policy.

"The whole point of 75-basis-point increases is to tighten financial conditions," said William Ackman, founder and chief executive of Pershing Square Capital Management.

"Each time Jay Powell has raised rates, ironically, he has eased financial conditions because of his unwillingness to acknowledge the Fed is prepared to take the country into a recession in order to eliminate the inflation scourge."

Fed officials are raising rates at the most aggressive pace since the 1980s. Until last month, the central bank hadn't raised rates by 0.75 point since 1994.

With Wednesday's action, the central bank has raised rates since March as much as it did between 2015 and 2018 and returned the fed-funds rate to a level last seen three years ago, before a slowing economy led the Fed to cut rates slightly. Officials slashed them to near zero in March 2020, when the Covid-19 pandemic raced around the world.

U.S. inflation has accelerated since March 2021. Demand surged **after** the **economy's reopening and aggressive government stimulus**, and **Russia's invasion** of **Ukraine** has **further aggravated supply-chain disruptions** and **driven energy and commodity prices up** this year.

How consumers and businesses respond to tighter money will help resolve one of the biggest questions facing the Fed and financial markets: how high officials will ultimately raise rates.

Another hot inflation reading earlier this month – the Labor Department reported its **consumer-price index rose 9.1% in June from** a **year before** – prompted investors to speculate that the Fed might increase the fed-funds rate by a full percentage point at this week's meeting. The Fed targets 2% inflation on average and uses a separate gauge, the personal-consumption expenditures price index.

Investors in interest-rate futures markets are betting that after raising the rate to around 3.5% at the end of 2022, the Fed will reverse course next year by lowering it.

Mr. Powell said Wednesday it was too soon to say how the rate path would evolve, but he pointed to projections officials submitted last month showing they expected to raise the fed-funds rate to around 3.5% this year and 4% next year.

Market expectations of rate cuts reflect a major misunderstanding about how the central bank is likely to react to slowing growth and rising unemployment with higher inflation, said Dan Morehead, chief executive and founder of hedge-fund firm Pantera Capital.

In recent years, low inflation has given the Fed more flexibility to quickly cut rates in reaction to growth slowdowns, but officials don't have that luxury right now. They are worried about consumers and businesses anticipating inflation to stay high.

"There's no working-age American who has traded [bonds] in a rising inflation environment," Mr. Morehead said. He thinks it is possible the Fed will raise the fed-funds rate to 5% or "some number that nobody can get their head around," he said.

Since the Fed raised rates by 0.75 point last month, several other central banks have accelerated their own rate increases. Investors have responded in ways that reflect growing worries about recession. Oil and commodity prices have declined. So have market- based measures of future inflation and bond yields.

The fed-funds rate, an overnight rate on loans between banks, influences borrowing costs throughout the economy, including rates on mortgages, credit cards and business loans. The housing market, as one of the most interest-rate sensitive corners of the economy, has been the epicenter of the Fed's effort to stimulate growth last year and to slow it this year. Prices of homes have surged amid strong demand, but sales are slumping now as rates rise sharply.

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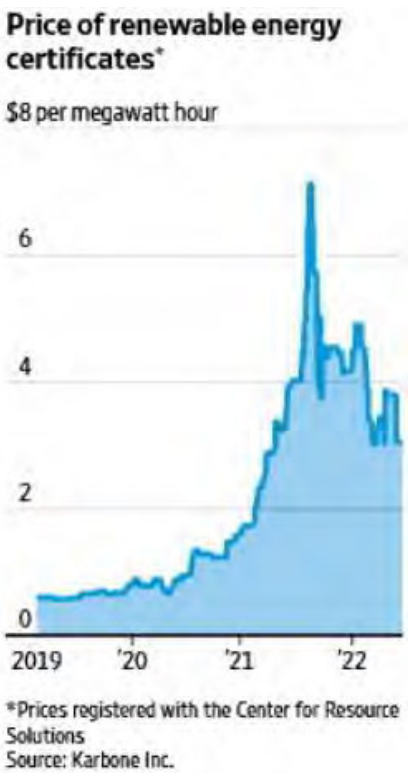
Going Green Costs Companies More as Demand Rockets

by Phred Dvorak and Katherine Blunt – WSJ – Jul. 6, 2022

As more companies pledge to neutralize their carbon emissions in response to climate change, **securing green power in** the **U.S.** is **getting much more expensive**.

Surging demand has pushed up the U.S. price of renewable energy certificates, a financial instrument that lets companies say they bought clean electricity from the grid. The **price of RECs** more than quadrupled at one point last year and is still around triple its level for most of the past decade, data trackers say.



Meanwhile, inflation and supply-chain bottlenecks are driving up costs for another way U.S. companies get their green electricity: by funding solar or wind projects directly in return for their power. Those costs have seen double-or even triple-digit percentage increases, green-energy experts say. "The market now is tough," said Misti Groves, vice president of market and policy innovation at the Clean Energy Buyers Association, a Washington, D.C., group for green-power buyers. Companies and governments the world over are increasingly focused on shifting to renewable energy as a way of reducing carbon emissions to help curb global warming. More than 5,000 companies have signed up with the United Nations' Race to Zero campaign, pledging to purchase clean energy and take other measures to help eliminate or offset the greenhouse gases they generate. Some 370 companies including General Motors Co. and Airbnb Inc. have joined a group, RE100, whose members pledge to be 100% powered by renewable energy by midcentury.

In the U.S., renewable energy certificates have long been the cheapest and most common way of procuring green power. The certificates represent the "greenness" of each unit of electricity generated by sources such as solar or wind, and can be bought separately from the power itself. Under current carbon- accounting rules, RECs let companies say they are buying clean energy – and thus have zero emissions – even though technically they are using electricity from a grid that can contain green as well as carbon- emitting sources of power.

For most of the past decade, the price for stand-alone RECs was less than $1 per megawatt hour, data trackers say. But last year, as more companies sought RECs to satisfy renewable energy targets, the benchmark price rose from around $1.60 per megawatt hour to more than $7 in August, before falling to around $3 recently, according to data from Karbone Inc., a financial services firm that specializes in renewable energy.

Some companies are fleeing stand-alone RECs in favor of buying clean electricity through long-term contracts with wind or solar developers, in hopes of getting lower, more stable prices.

But the cost of such power-purchase agreements has been soaring, too, pushed by increasing demand as well as supply chain issues, inflation and long wait times to receive necessary approvals to connect new projects to the electric grid.

A report by LevelTen Energy, a renewable-energy marketplace, found that in competitive power markets, **prices for long-term contracts** for **wind and solar-power purchases**, which are used to finance new projects, **jumped** by **15.8% for solar** and **41.5% for wind** during the **first quarter** of **2022**, **compared with** the **previous year**.

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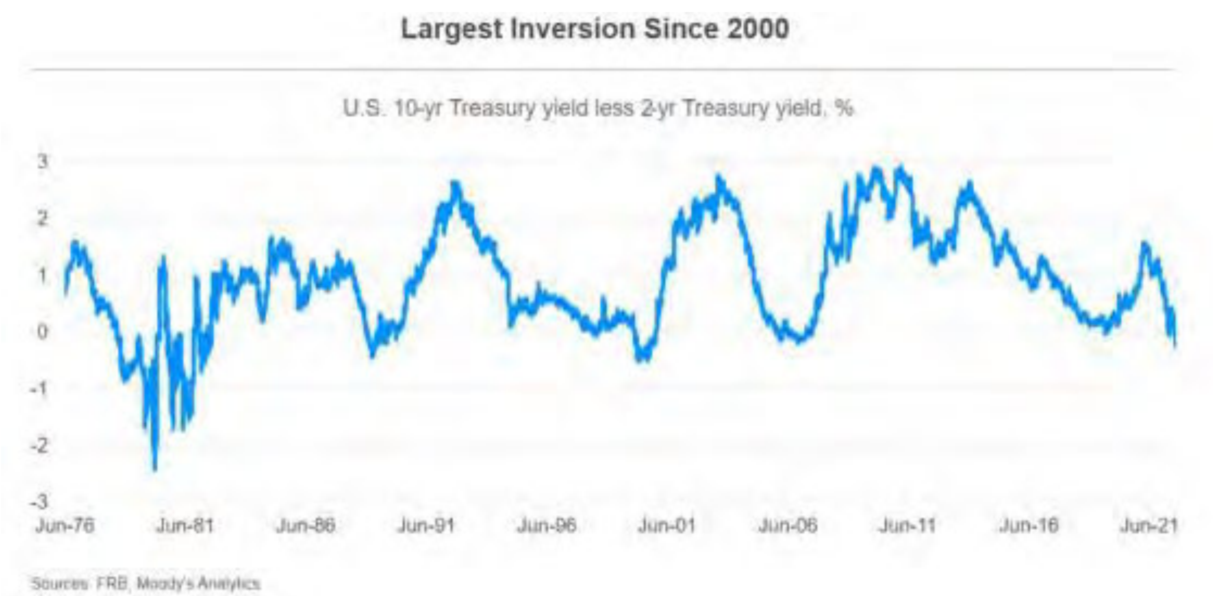
How Inverted Could the U.S. Yield Curve Get?

by Ryan Sweet and Kamil Kovar – Moody's Analytics – Aug. 4, 2022

The **U.S. yield curve has been inverted for four weeks** and is among the **most inverted in decades**. This is sending an **ominous sign about recession risks**, but **how much more inverted could the yield curve become**? **Historically**, the **largest inversion between** the **10- and two-year Treasury yields occurred** during the recessions in the early **1980s**, as then Federal Reserve Chairman Paul Volcker was aggressively raising interest rates to tame inflation. The yield curve was systematically inverted by around 50 basis points and at one point by more than 200 basis points, which makes Wednesday's inversion of 37 basis points seem somewhat benign. However, since then, inversions rarely have exceeded 20 basis points and reached a maximum below 50 basis points in 1989 and 2000. Could the current inversion exceed these values?



Contrast the traditional view of inversions and their role in signaling recession with what is happening during this tightening cycle. The traditional view holds that yield-curve inversions happen when the Fed either tightens too far by mistake, or when it fails to react to a weakening economy in time. In either case, financial markets foresee the need for lower rates in the future, causing an inversion between the short-term and the long-term yields, since the short-term yields reflect the currently high policy rates. In such a situation, the inversion is an accident caused by too tight of a policy stance, not part of a plan.

This cycle is following a different script. According to the Fed's dot plot, the Fed plans to take the federal funds rate temporarily above neutral; the dot plot has the federal funds rate significantly higher at the end of 2022 and 2023 than the long run rate of 2.5%, making the dot plot itself inverted. If that script is followed, then the inversion will not be accidental but rather intentional. And **intentional inversions** are very **different from inadvertent ones**

Currently, the best example of this mechanism is on display in the Czech Republic and Poland. Both central banks intentionally took policy rates way above neutral levels in order to prevent inflation expectations from de-anchoring. Since both are communicating that they expect to take policy rates lower in due course, this caused abnormally large inversions of close to 200 basis points.

The **main takeaway** is that the **U.S. yield-curve inversion** in **this cycle could** get **much larger than** in **previous cycles during** the **last three decades**. It could end up resembling the inversion seen in the early 1980s, since now as then the Fed's plans call for an intentional inversion. The **other takeaway** is that this time around **inversion might not be** as **precise** a **signal as usual about** an **upcoming recession**. Part of the forecasting power of inverted yield curves comes from bond prices signaling that the economy is weakening and will need lower interest rates in the near future. However, **this time** around, the **inversion** will be **more about** the **Fed's intentions than** about **market expectations of recession**, which **might mean** that **yield-curve watchers will overstate recession risks.**

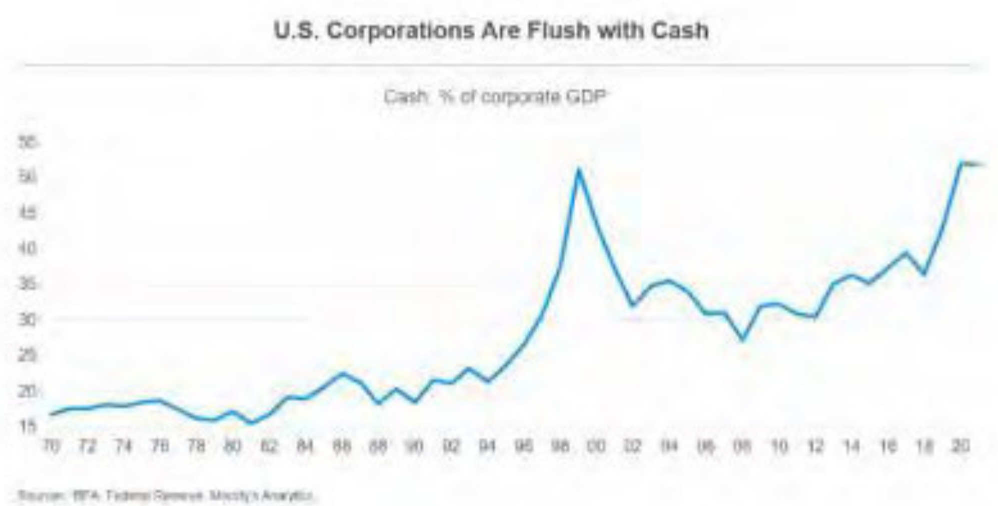
Of course, **this rests on** the **assumption** that the **Fed's dot plot should be believed**, **and** that the **Fed will be able to follow** the **charted course**. **Both assumptions might not be true**. The Fed might say it plans to hike more than it actually does in order to send a more powerful signal to markets. This might cool inflation without the need to implement as many hikes. Or alternatively, the Fed might be planning to take rates above neutral, but the economy will break before the Fed gets that chance. In this, the Fed's situation is very different from the Czech or Polish central banks, since their tightening has a much smaller effect on their respective economies, so they can tighten more than the Fed can without breaking the economy. Therefore, it is unlikely that inversion would get as large as in those countries. So, while recent inversions are likely to get topped, the **Volcker-era records for inversion** are **likely safe.**

A Summer of Spurts

Summer is normally a quiet time for U.S. corporate bond issuance, but this year, issuance is occurring in spurts. Companies are taking advantage of the recent slide in interest rates and attempting to get ahead of the Federal Reserve, which has clearly signaled that it will continue to front-load rate hikes. **A 50-basis point hike** in **September** is **likely**, **but** there is the **risk** of a **75-basis point hike if** the **inflation data** continue to **come in hotter than expected**. Companies are trying to tap the investment or high-yield corporate bond markets before rates rise.

While more deals are occurring in both the investment grade and high-yield corporate bond markets, companies are still paying larger concessions. Investors have been dipping their toes into the high-yield corporate bond market, which had been ice cold this year. However, investors are demanding some additional concessions. There was little issuance immediately after last week's meeting of the Federal Open Market Committee, but the high-yield corporate bond market has come to life recently.

Investors are still cautious, **prioritizing quality as** the **economy has clearly slowed**. The weakening in the U.S. economy has fanned concerns about an increase in credit risk, since corporate earnings are not immune to a deterioration in the U.S. economy, particularly if a recession takes hold. Corporate debt has surged recently, which is another concern, particularly as higher interest rates are going to add billions to corporate interest expenses.



Despite the drop in the default count from last month, the trailing 12-month global speculative-grade default rate held steady at 2.1% at the end of June, the same reading from the end of May. Corporate default rates in the U.S. remain low, at 0.8% in June. Looking up and down the credit ladder, defaults are highest among those companies rated Caa_C. The **investment grade default rate was 0% in June** while it was 1.4% for speculative grade. Default rates will likely rise further but remain fairly low.

One reason that **defaults** are **unlikely** to spike is that **U.S. companies are flush with cash**. Cash as a share of corporate GDP is more than 50%, which is noticeably higher than prior to the pandemic and among the largest since the 1970s. Having U.S. corporations flush with cash should limit the rise in corporate defaults, barring any enormous economic disruption.

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U.S. Inflation Hits New Four-Decade High of 9.1%

by Gabriel T. Rubin – WSJ – Jul. 13, 2022

Prices up broadly across the economy, with **gasoline** far **outpacing other categories**.

Retailers have warned about the need to discount goods, which is expected to subdue some price pressures in coming months.

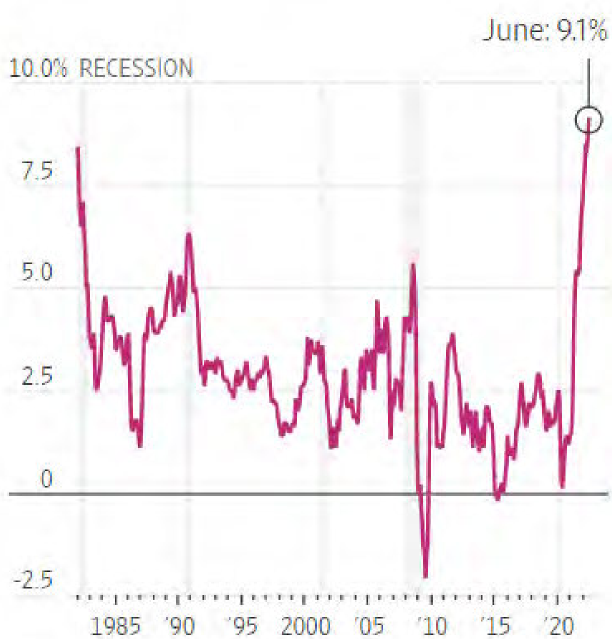
U.S. consumer inflation rose to a new four-decade high at an **annual rate** of **9.1% in June**, extending a year and a half stretch of persistently higher prices.

The **consumer-price index's rate of increase last month** was the **highest since December 1981**, the Labor Department said Wednesday. It also eclipsed May's annual rate of 8.6% that led Federal Reserve officials to shift to a faster pace of benchmark interest-rate increases in its campaign to bring down inflation.

The report **likely** keeps the **Fed** on track to **raise** its **benchmark interest rate** by **0.75 percentage point** at its meeting **later this month**. **Stocks dropped** and bond **yields jumped following** the **inflation report**.

Core prices, which exclude volatile food and energy components, increased by 5.9% in June from a year earlier, slightly less than May's 6.0% gain, the Labor Department said.

Consumer-price index, change from a year earlier



Source: Labor Department

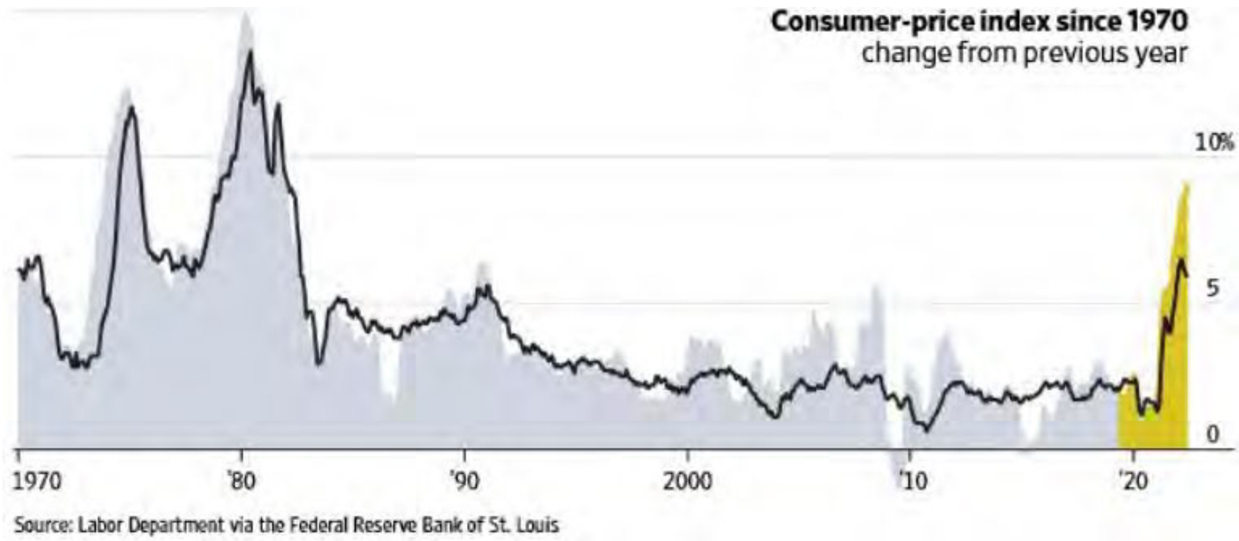
As inflation climbs in the U.S., rising food and energy costs have pushed the nation's most popular price index to its highest level in four decades. WSJ's Gwynn Guilford explains how the consumer-price index works and what it can tell you about inflation. Illustration: Jacob Reynolds

On a month-to-month basis, core prices rose 0.7% in June, a bit more than their 0.6% increase in May – a sign of inflationary pressures throughout the economy.

The report showed few signs of relief from higher prices. Costs were up broadly across the economy, with gasoline far outpacing other categories with an 11.2% gain over the prior month. Gasoline prices have been on a downward path in recent weeks. **Shelter** and **food** price increases were also major contributors to inflation, the Labor Department said.

"This report will make for very uncomfortable reading at the Fed," said Ian Shepherdson, chief economist at Pantheon Macroeconomics.

Despite June's inflation reading, economists point to recent developments that could subdue price pressures in the coming months.



Investor expectations of **slowing economic growth world-wide** have **led to a decline** in **commodity prices** in recent weeks, including for **oil**, **copper**, **wheat** and **corn**, **after** those **prices rose sharply following** the **Russian invasion** of **Ukraine**. Retailers have warned of the need to discount goods, especially apparel and home goods, that are out of sync with customer preferences as spending shifts to services and away from goods, and consumers spend down elevated savings.

"There's a pretty serious **recession fear** affecting a broad range of asset prices," said Laura Rosner-Warburton, senior economist at MacroPolicy Perspectives.

Retailers' ability to shed unwanted inventory could test whether pricing is returning to pre-pandemic patterns, Ms. Rosner-Warburton said. Some retailers, such as Target, have already said they are planning big discounts. Others with robust warehouse capacity, such as Walmart Inc., could be more likely to hold on to their excess inventory, analysts say.

"It would be really important if we do see discounting return, because it would show that we weren't that far away from the pre-Covid environment in terms of pricing behavior," Ms. Rosner-Warburton said.

Discounts haven't shown up prominently in inflation figures so far: Prices for apparel and home goods both rose last month. New and used car price increases, a significant source of upward pressure on inflation, both eased on a month-to-month basis in June.

The Fed last month raised its interest-rate target by 0.75 percentage point, the largest increase since 1994. Slowing demand is key to the Fed's goal of restoring price stability in an economy that is still struggling with supply issues, but raising interest rates also elevates the risk of a recession.

It also is trying to prevent consumer expectations of higher inflation becoming entrenched, since such expectations can be self-fulfilling. Fed Chairman Jerome Powell has said the central bank wants to see clear evidence that price pressures are diminishing before slowing or suspending rate increases.

Persistent high inflation is putting a strain on businesses and consumers who, after decades of price stability, aren't used to it.

Left: High inflation and a poor farm season have driven Dan Waag to close Arlene's Sunny Side Cafe in Alcester, S.D., for a week.

Dan Waag, 55 years old, the owner of Arlene's Sunny Side Cafe in Alcester, S.D., made the difficult decision to close for a week after concluding that a drop in the number of customers was leaving the restaurant's finances in the red.

"I know these are tough times with this inflation, little to no rain for the farmers, gas prices as high as they are," he wrote to his customers on Facebook.

Mr. Waag attributes the slowing demand to a poor season for the corn and bean farmers in the area, and the added toll of higher gasoline prices that might make an outing to his restaurant an unaffordable luxury. He hasn't changed his prices yet, but with his own rising costs and a drop in daily revenue from around \$600-\$700 to \$300-\$400, he feels he may have to soon.

By closing for a week, he said he is betting customers will realize the value of having a non-fast food restaurant in their town of around 800 people. "I'm trying to show people, 'This is what it will be like if I have to stay closed,' " Mr. Waag said.

Consumer inflation expectations have improved somewhat, according to a **Federal Reserve Bank of New York survey** this week. **Americans expect slower inflation increases over** the **longer run** than they had in recent months. The bank said in its June Survey of Consumer Expectations that respondents see the annual inflation rate three years from now at 3.6%, down from their expectation in May of 3.9%. The bank also said respondents expect the annual inflation rate five years from now to be 2.8%, down from their May expectation of 2.9%.

Higher interest rates won't have the same effect on all prices simultaneously, economists say. Costs such as mortgages and rents – a big part of household budgets – respond over time to the demand-sapping effects of higher interest rates. Shelter costs rose by 0.6% in June over the prior month, the same rate as they did in May. The rent index rose 0.8% over the month, which was the largest monthly increase since April 1986.

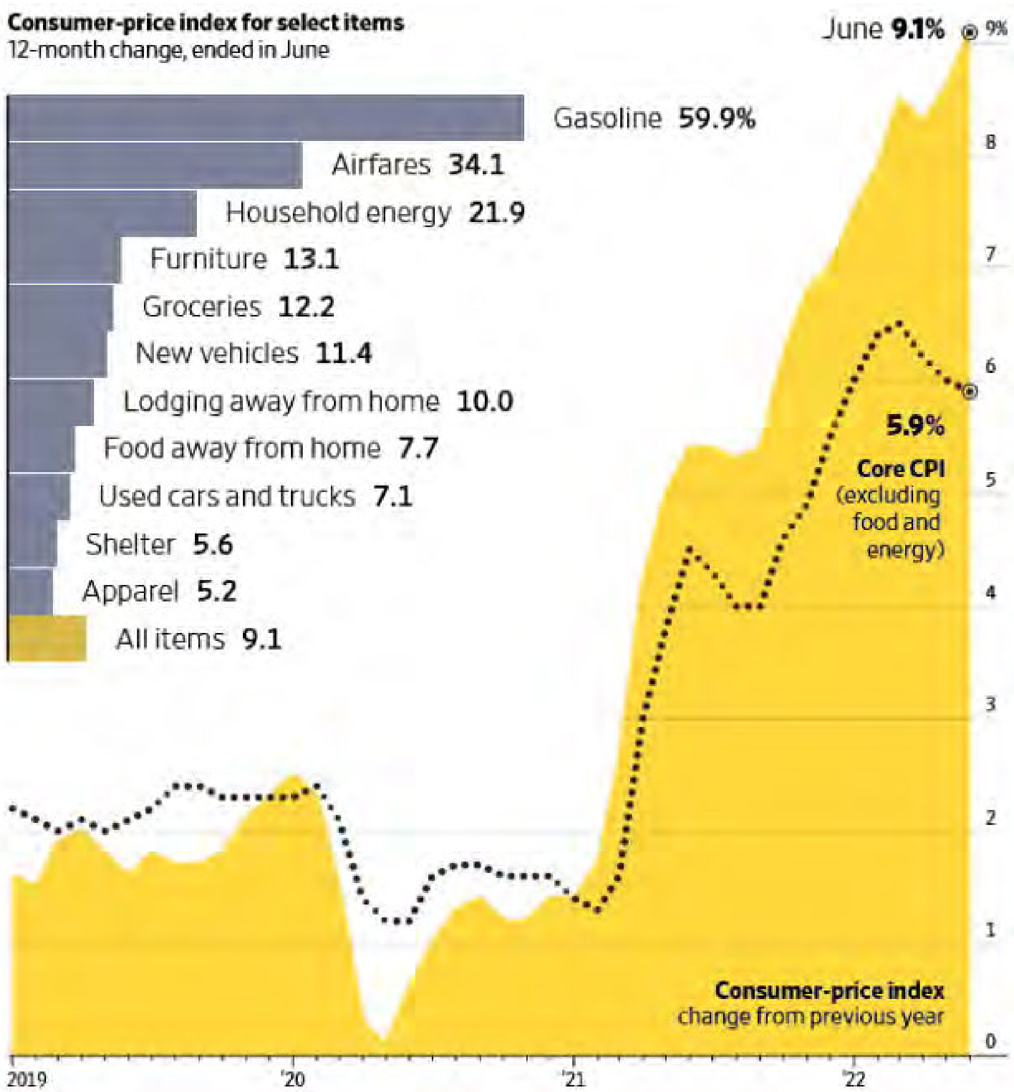
Housing inflation is important because it **represents** around **40% of core CPI and** around **17%** of the **Fed's preferred inflation gauge**, the **Personal-Consumption Expenditures Price Index**.

"High rents are really troubling because they're locked in once every year or once every two years, and that's what leads people to go ask their boss for higher wages," said Lara Rhame, chief U.S. economist for FS Investments.

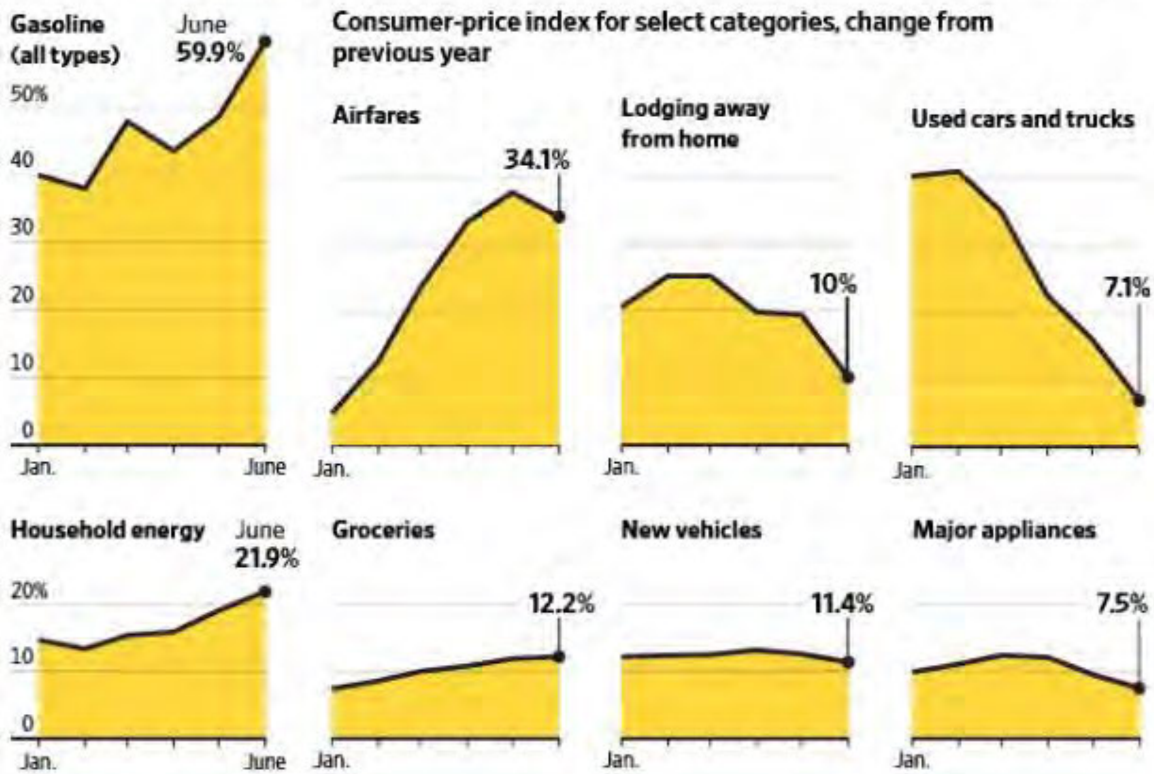
Wages aren't keeping up with inflation. With annual wage growth at 5.1%, average hourly earnings adjusted for inflation are declining at their fast pace in four decades. **After accounting for seasonal and inflation adjustments, average hourly earnings decreased 3.6% from June 2021 to June 2022**.

Record home prices and **higher mortgage rates** in May made it the most expensive month since 2006 to buy a home. Those conditions are leading prospective buyers to drop out of the market for now. But with limited supply and continued demand, it may take months before housing prices see significant declines.

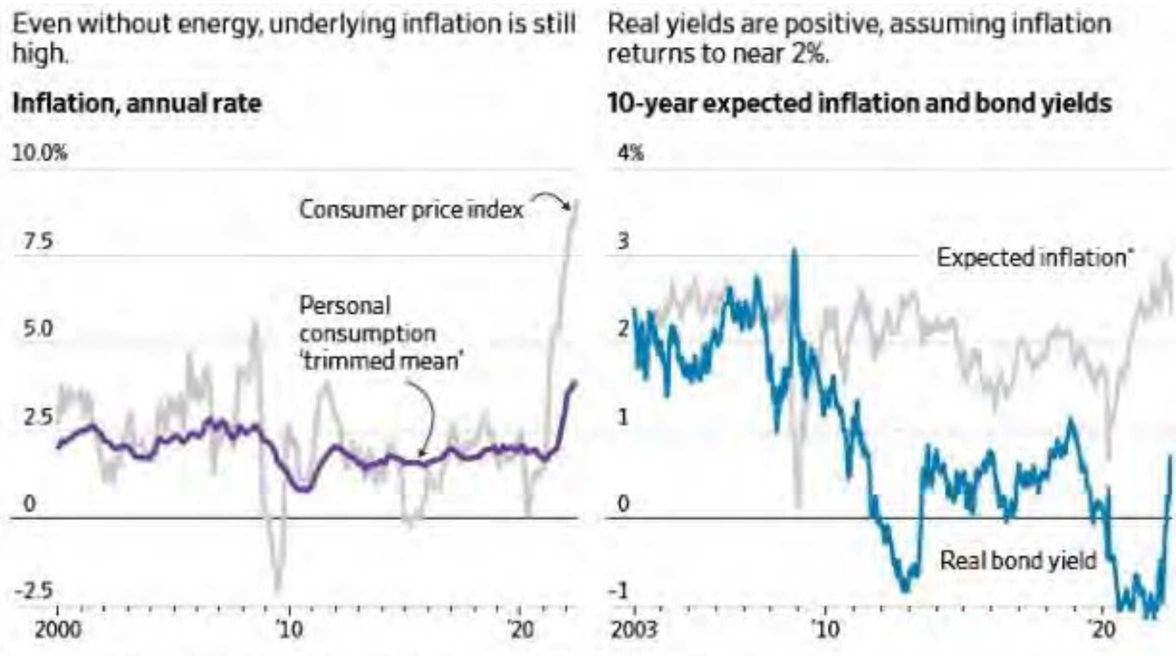
"We entered this year with so much more demand than supply – even with many home buyers unable to compete in the market, there's still a lot of buyers," said Bill Adams, chief economist at Comerica Bank.


Consumer-price index for select items
12-month change, ended in June
Gasoline 59.9%
Airfares 34.1
Household energy 21.9
Furniture 13.1
Groceries 12.2
New vehicles 11.4
Lodging away from home 10.0
Food away from home 7.7
Used cars and trucks 7.1
Shelter 5.6
Apparel 5.2
All items 9.1
June 9.1%
9%
8
7
6
5
4
3
2
1
0
5.9%
Core CPI
(excluding
food and
energy)
Consumer-price index
change from previous year
2019
'20
'21
'22

While prices for gasoline and food continue to rise, prices for big-ticket and travel-related items, such as airfares, used cars and trucks, new vehicles and major appliances, show signs of easing.



Source: Labor Department



*Expected inflation implied by difference between nominal and inflation indexed bond yields
Sources: Federal Reserve Bank of Dallas (trimmed mean PCE index); Labor Dept. (CPI); Federal Reserve Bank of St. Louis (expected inflation, bond yields)

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Investors Fear Quick End to Rally

by Karen Langley – WSJ – Aug. 2, 2022

Economic and earnings concerns weigh on outlook despite surge.

Bearish investors aren't buying into hopes that July's rapid advance for stocks heralded the start of a new bull market.

If anything, they say the worst might be yet to come as inflation remains high, the Federal Reserve plans more interest- rate increases and stocks trade at **valuations** that **still don't look cheap**.

"We don't think the market has bottomed," said David Spika, president and chief investment officer at GuideStone Capital Management. With earnings expectations yet to meaningfully decline, he said that "We clearly have not priced in a recession."

That view is at odds with the market's sudden appetite for stocks. After a punishing first half, the S& P 500 rallied 9.1% in July, its strongest month since November 2020. The gains pared the index's year-to-date decline to 13%. On Monday, the S& P 500 began August by slipping 0.3%.

Although **Fed Chairman Jerome Powell** sounded warning notes during his press conference last week, markets chose to view them as being less hawkish than many had feared. That **reinforced views** expressed in the bond markets **that while** the **Fed will continue to raise interest rates for some time**, it will **then have to quickly pivot** and **begin lowering them**.

Those with a more glass-half empty view believe markets are getting ahead of themselves with such thinking.

Data last week showed the economy contracted for a second consecutive quarter, intensifying debate over **whether the U.S. is headed for** – **or already in** – a **recession**. While analysts recently made cuts to their forecasts for corporate earnings, many investors say they believe the projections are still too high.

Investors this week will parse the next round of earnings reports from companies including Caterpillar Inc., PayPal Holdings Inc., Star-bucks Corp. and CVS Health Corp. for clues about the market's trajectory. They also will scrutinize the latest jobs report to gauge how employment is holding up as the economy shows signs of weakness.

As everyone from portfolio managers to corporate executives to central-bank officials tries to gauge the path forward, conflicting signals have clouded the outlook.

Economic output has fallen and the housing market has cooled.

The **bond market** is **flashing** a **classic recession warning.** The **two-year U.S. Treasury** note is **trading** at a **higher yield** than that of the **10-year** benchmark note as investors bet the Fed will raise interest rates through yearend but then switch to cutting them.

At the **same time**, **employers** have been **adding hundreds** of **thousands** of **jobs each month**, rounding out a **picture** that **doesn't look like th**at of **any recent U.S. recession.**

After the Fed raised interest rates last week, Mr. Powell cited job growth as he dismissed worries that the economy is in a recession.

Recent earnings reports have raised concerns, however, that consumers might begin to buckle as **inflation remains at** a **four-decade high**.

Walmart Inc. warned last week that **elevated prices** for **food and fuel** were causing customers to pull back, forcing the country's largest retailer to cut prices to reduce merchandise levels. Walmart lowered its profit outlook for the second quarter and fiscal year, sending its shares down 7.6% in the next session.

"Some might argue that the market is already down so much, isn't it already anticipating these negative estimate revisions?" said Ellen Hazen, chief market strategist and portfolio manager at F. L. Putnam Investment Management Co. "I think Walmart tells you that no, that was actually still a surprise."

Walmart warns high prices for food and fuel have caused customers to pull back, forcing the country's largest retailer to cut prices.

Analysts have been trimming their earnings expectations for the year. They now anticipate that profits from S&P 500 companies will grow by 8.9% in 2022, down from projections for 10.2% growth at the end of June, according to FactSet.

Given current earnings expectations and the stock-price declines this year, many investors say the market looks fairly valued after a period of trading at lofty valuations. The S&P 500 traded last week at about 17 times its projected earnings over the next 12 months, roughly in line with its average over the past 10 years, FactSet data show.

But others worry that analysts have been too timid in cutting their profit forecasts as the economy slows and monetary policy tightens, suggesting that stocks might not be so reasonably priced after all.

"With earnings at risk, our concern is that the P/E isn't really reflecting reality," said Saira Malik, chief investment officer at Nuveen. "If earnings decline, then your P/E is actually higher than it looks."

For signs that the stock market might soon find a bottom, investors are scrutinizing signals from the Fed. Many believe stocks will struggle to sustainably advance until the central bank halts its rate-raising campaign. Others are looking for indications that the market has come to expect company profits will be lower than today's forecasts suggest.

Jimmy Chang, chief investment officer at Rockefeller Global Family Office, said a shift in monetary policy features prominently on his list of potential reasons to become more positive about risk assets such as stocks.

"At a minimum you want the Fed to be neutral, not tightening," Mr. Chang said. "That's the bare minimum, and we're not there yet."

Shares of Boeing rose 6.1% after the plane maker temporarily avoided a strike at three defense manufacturing plants and cleared a regulatory hurdle.

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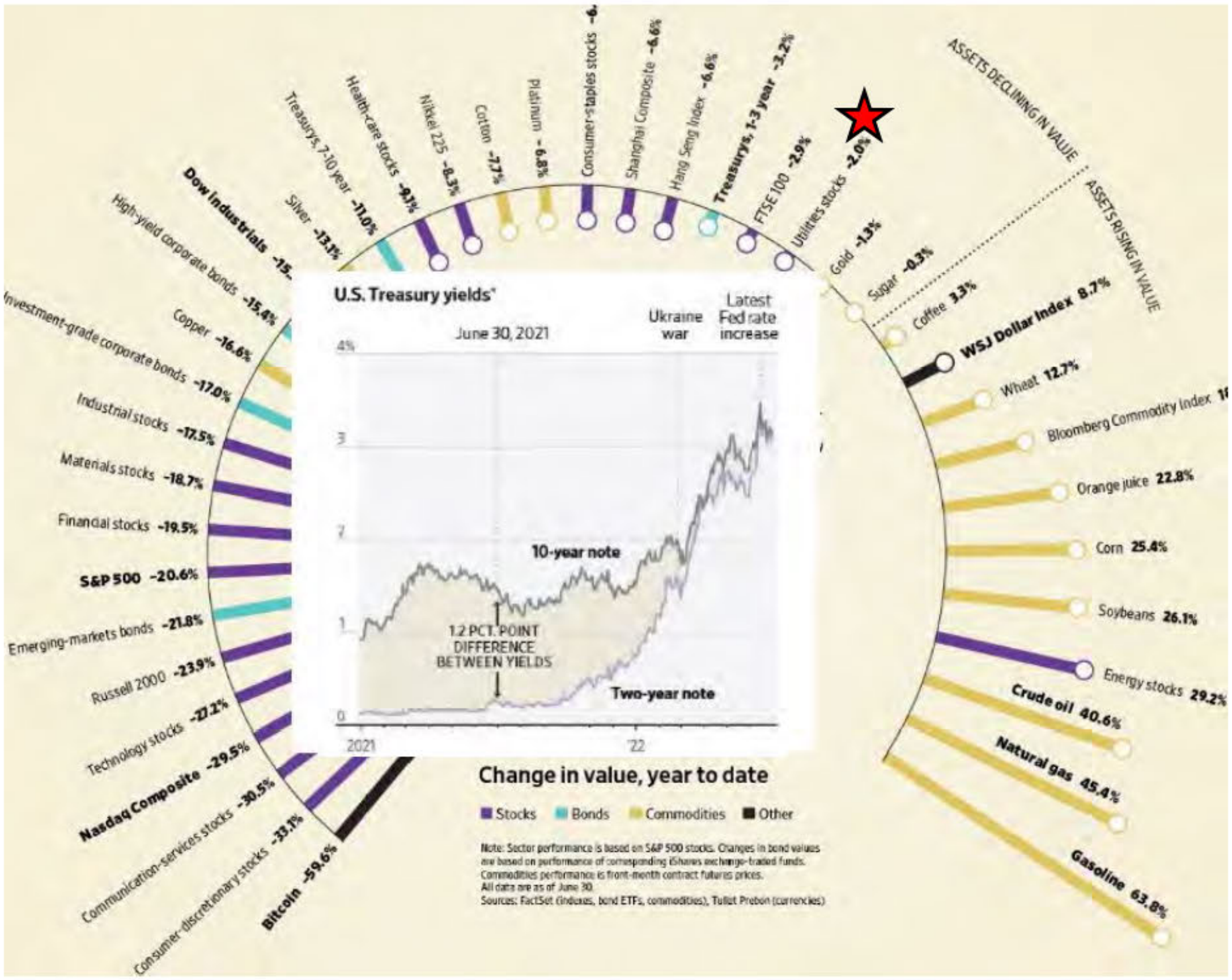
It Can Always Get Worse

by James Mackintosh, Streetwise Column – WSJ – Jul. 2, 2022



The first six months of the year were full of surprises for markets, from surging inflation to a cryptocurrency implosion.

Get ready for more unexpected shocks in the second half.

We're halfway through the year, but markets are beginning to fear we're not even halfway through the bad news 2022 has in store. The first six months were full of surprises: Inflation. The biggest selloff in bonds in four decades. A plunge in tech stocks rarely matched in history. And the implosion of crypto.

The looming risk that investors ignored for months is recession. But whether the economy will slump or be just fine remains unknown. Attempts to put a probability on it range from 90% in a Deutsche Bank survey of clients to the spurious precision of 4.11% in the New York Federal Reserve's recession forecasting model.

While investors are at last focused on **recession uncertainty**, **risks elsewhere** in the world could hit U.S. investors, too. Japan might finally be forced to relent and allow bond yields to rise, which would suck back cash the country's investors had poured overseas. In Europe, the central bank has promised a new plan to support Italy – but we've seen this show before. If it follows the pattern of too little, too late, we could see a return of the euro-zone debt crisis, something markets are not prepared for.

Almost any economic outcome is likely to prove a fresh surprise. If there's a soft landing, stocks should do well as the recent recession panic reverses. If there's a recession, there could easily be a big loss still to come, since only the drop of recent weeks appears to be related to recession risk.

There's one sliver of good news: Prices are already down a lot, which brings them closer to wherever they will eventually bottom out. The **S&P 500 has fallen by** the **most in** the **first half of** a **year since** the **21% loss in 1970**, **when** the **economy was in recession**. **Long-dated Treasurys lost 10%** even including coupon payments, the biggest six-month loss since Paul Volcker's Fed forced the economy into recession in 1980.

There's no sure way to work out what probability the market is putting on the Fed driving the economy into recession this time. J.P. Morgan strategist Nikolaos Panigirtzoglou says the simplest way to extract probabilities from the price moves is to compare price falls with the average peak-to- trough fall of past recessions.

Since the S&P 500 is down 21% and the average fall in the last 11 recessions was 26%, that suggests an almost 80% chance of recession is priced.

Yet, much of this year's selloff wasn't about recession risk. To see this we need to distinguish the direct and indirect effects the Fed has on prices of stocks and bonds.

The direct effect is to push up bond yields and push down valuations of stocks with profits far in the future. This is what dominated until June, with growth stocks crashing while cheap "value" stocks were basically fine.

Then it all changed. Investors woke up to the indirect effect of the Fed, which is to weaken the economy. This has almost the opposite effect on asset prices. A weaker economy means less inflation than otherwise, justifying lower bond yields. It also hits earnings, particularly for cyclical companies, which tends to hurt stocks with relatively low valuations more than growth stocks.

Since June 7 cheap stocks have been hammered and cyclical sectors – especially oil stocks and miners – have plummeted. In the past two weeks recession fears showed up in Treasurys too, as investors bet that the Fed will have to cut rates aggressively next year.

The drop of almost half a percentage point in the 10-year Treasury is the most over such a period since the first pandemic lockdown. Wall Street analysts have also been racing to cut their earnings forecasts, after ignoring recession risks.

The markets now understand the outlook is clouded, so will be less bothered by a sudden shower. But investors will still get drenched if the storm of a deep recession washes away earnings.

There are clear risks that could be imported from abroad. Hedge funds are betting big that the Bank of Japan will abandon its bond yield controls, which have shielded it from tightening global monetary policy and crushed the yen. If the hedge funds are right, Japanese bond yields would leap and the yen's extreme weakness go into sudden reverse, roiling markets globally.

The risk from Europe is familiar: politics. The European Central Bank acted early to head off a crisis in Italy's government financing. It now has the difficult job of persuading the frugal north to accept a deal underwriting the country's bonds, without imposing unacceptable conditions on Italy.

I remain hopeful that recession will be mild, not hit until next year, and perhaps be avoided altogether. But the economic data are going the wrong way, and higher interest rates haven't even begun to bite on ordinary households yet. The dangers are big, and the markets are still not fully prepared.

The first six months of 2022 were full of unexpected market shocks

The Selloff, and What Comes After

The first half of the year was a wild one for investors, and the stage is set for more big moves in the second half of 2022. Here's what the data is telling us about what might lie ahead for business and the economy.

Soaring inflation, **rising interest rates** and the **specter** of an **economic downturn** all contributed to a 21% decline in the S&P 500 in the first six months of 2022. Since 1960, the S&P 500 has had just two first-half losses greater than this year's drop – with the last coming more than half a century ago.

Many of the large tech-related companies that drove the rise of the S& P 500 in the past decade dragged it into a bear market this year. That reversal is evident in this year's 34% decline through Thursday by the NYSE FANG+ Index, which tracks Apple Inc., Amazon.com Inc., Microsoft Corp., Google-parent Alphabet Inc. and a handful of other large companies.

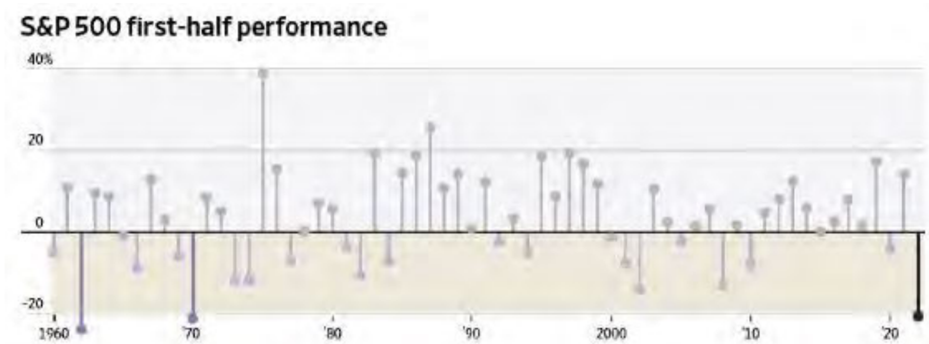
The Federal Reserve's interest-rate increases have been one reason tech shares have been so hard-hit. Such hikes can hurt demand for tech shares because they cause the market to devalue future earnings of growth companies.

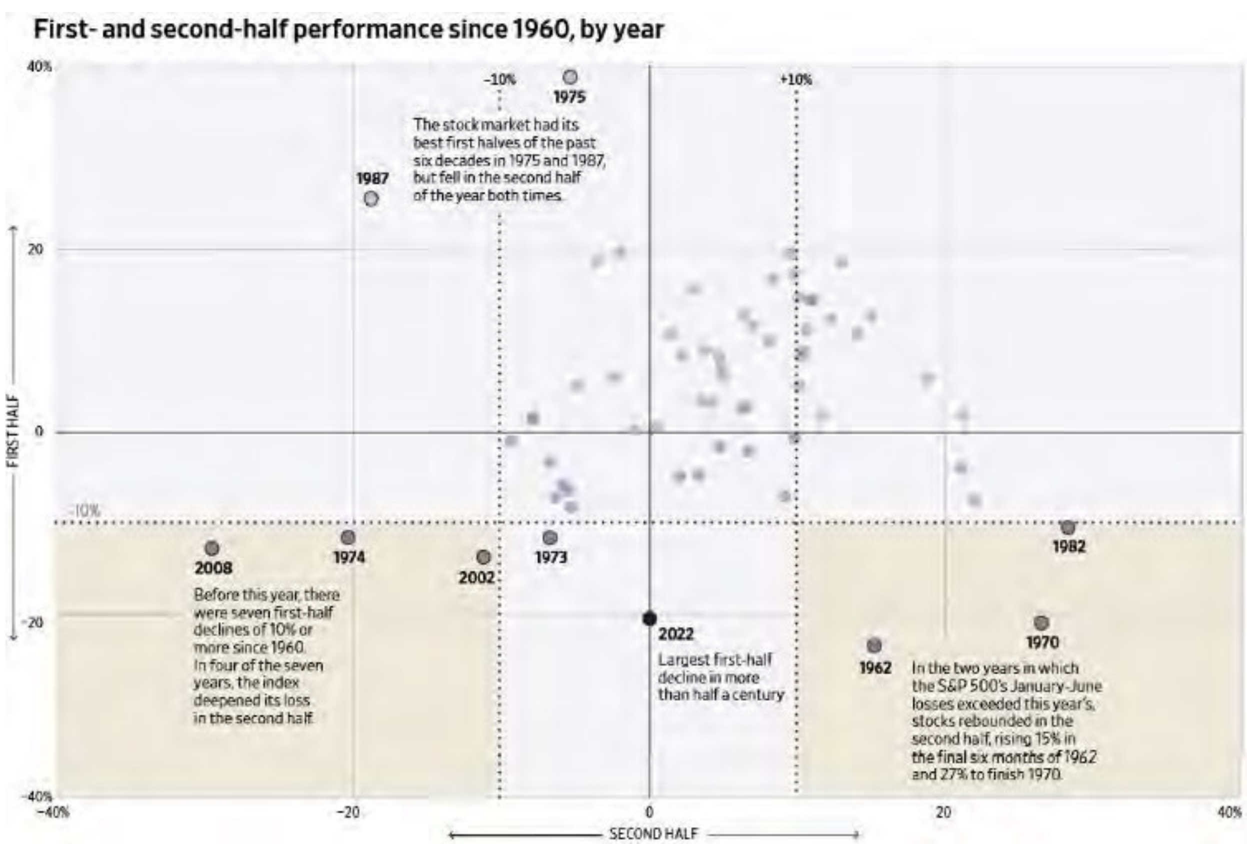
As investors look ahead to the second half of the year, they are asking how much farther asset prices will fall before they reach the bottom. History shows that stocks have tended to make a big move in either direction following a first-half swoon. In six of seven years that the S&P 500 fell by 10% or more through the first six months, the index rose or fell in the second half by at least 10%.

The selloff hit more than just the stock market. Bonds and crypto-currencies took big hits, and – with the specter of a recession on the horizon – there were large declines in commodities linked to the health of the economy.

Commodities

Futures prices for U.S. natural gas earlier this year reached their highest level in more than a decade. The run-up was in part due to growing demand abroad, as European countries focused on reducing their reliance on Russian gas after the **invasion of Ukraine**.





The invasion has also affected **wheat prices**. The Russian blockade of Ukraine's ports has hindered the movement of goods out of the country, one of the top grain exporters in the world.

Copper is used in electronics, cars, home building and elsewhere, so copper's **decline** is a reflection of investors' dimming outlook for the global economy. Declines in **platinum and lumber** indicate similar pessimism.

Bonds

Rising inflation, combined with expectations of more interest-rate increases, have contributed to a selloff in the bond market this year.

The **yield** on **10-year Treasurys rose** to its **highest level since 2011**, but there was an **even more notable increase** in the **yield** of the **two-year note**. **Bond yields rise as prices fall.**

The **two-year's convergence** with **longer-dated bonds** is an **indicator** that the market is anticipating a **possible near-term U.S. recession**.

This **red flag** is known as the **flattening** of the **yield curve**.

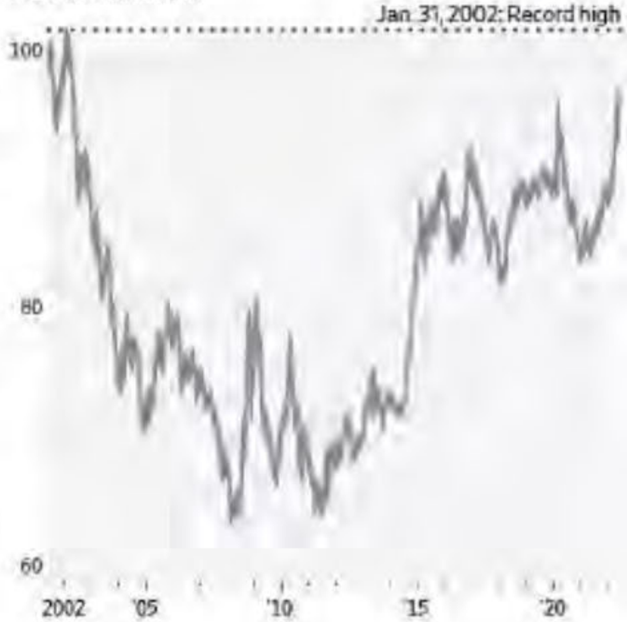
The dollar

The value of the dollar reached multidecade highs in the first half, driven by rising U.S. interest rates and weak overseas economic conditions.

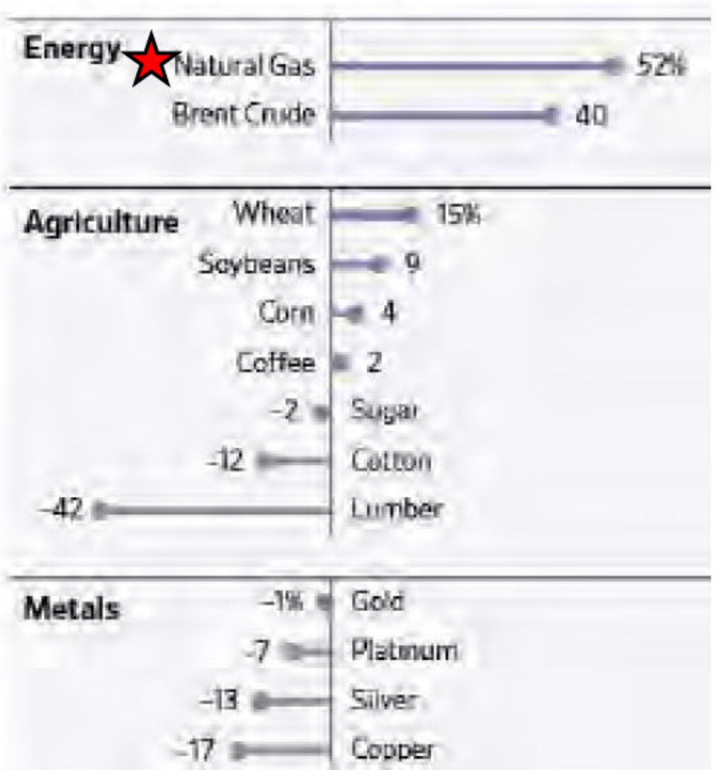
A strong dollar can help combat inflation because it makes imported goods less expensive, but it can also curtail economic growth. U.S. products become more expensive for foreigners, and American companies receive fewer dollars in exchange for their overseas exports.

Microsoft, for example, cut its sales and earnings guidance in June because of the impact of foreign exchange rates. Investors will be watching for additional evidence of the dollar's impact on company revenue in the second half of the year.

WSJ Dollar Index*



Futures prices, first-half change*



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SHRM

Jobless Claims Continue to Tick Up

by Roy Maurer – SHRM – Jul. 14, 2022

[Jobless Claims Continue to Tick Up (shrm.org)]

States reported that 244,000 workers filed for new unemployment benefits during the week ending July 9, an increase of 9,000 from the previous week's level. The number of workers continuing to claim unemployment benefits – 1.3 million – is well below the pre-pandemic average of 1.7 million.

Jobless claims have remained near pre-pandemic levels since early this year, as employers have generally avoided laying off workers due to historically high demand. But claims have slowly climbed since hitting a 53-year low this spring and it is being reported that more layoffs are being planned. Job cuts have accelerated from the technology sector into the automotive, consumer products, entertainment, financial and real estate sectors.

U.S. employers added 372,000 jobs in June, and the unemployment rate held at 3.6 percent, despite fears of a looming recession.

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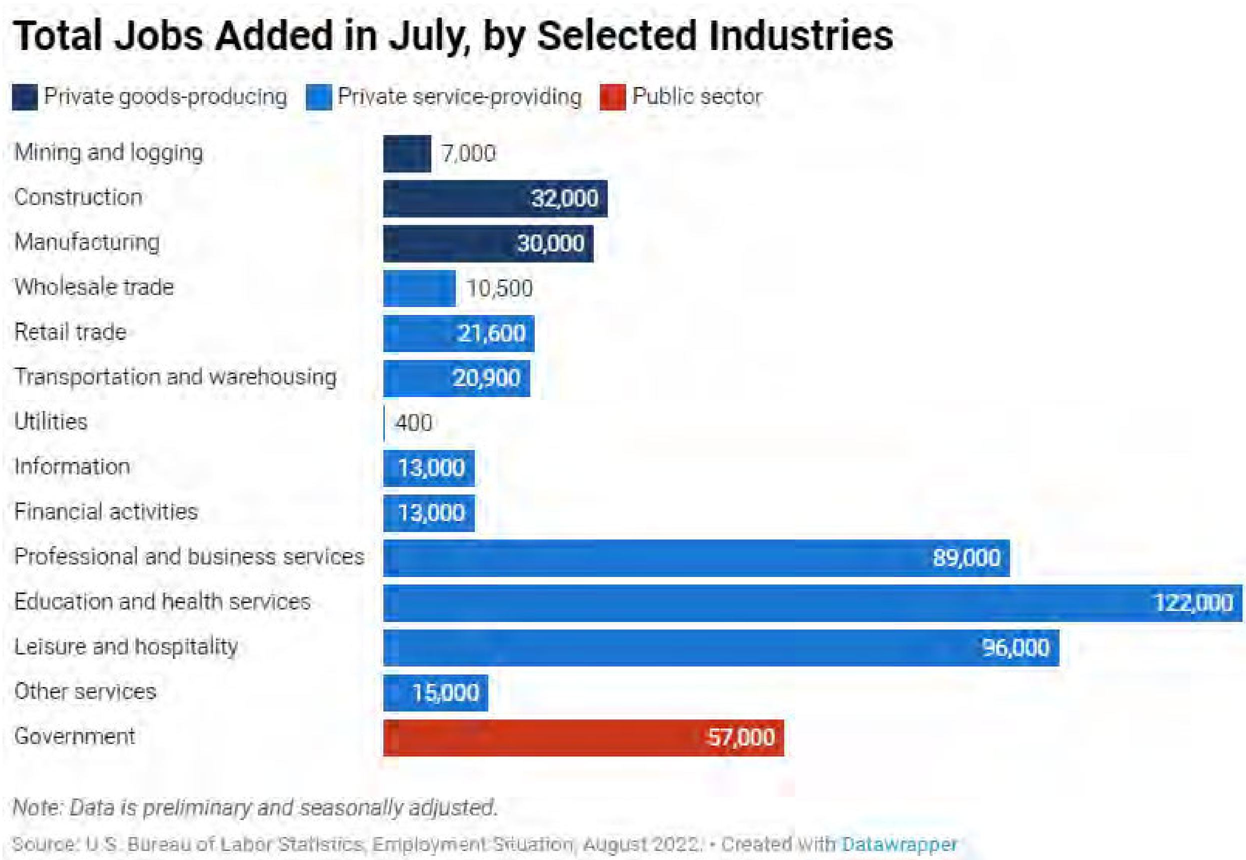
Jobs Grew By 528K in July
by Roy Maurer – SHRM – Aug. 5, 2022
[Jobs Grew By 528K in July (shrm.org)]

Payrolls are finally back to pre-COVID level; unemployment rate dropped to 3.5 percent.

U.S. employers added 528,000 new jobs in July, surpassing economists' forecasts, according to the latest employment report from the **Bureau of Labor Statistics**. The **unemployment rate ticked down to 3.5 percent**, **close to** what is considered **full employment and** a **half-century low**.

Overall employment has **finally returned to** the **prepandemic level last seen** in **February 2020**. Gains were broad-based, with the biggest increases reported in professional and business services, leisure and hospitality, and health care.

Labor market benchmarks remain the strongest argument against a looming recession, although a separate government report released last week showed back-to-back quarterly declines in GDP, signifying that the economy meets the technical criteria for a recession. And **headwinds** from the **highest inflation** in **four decades** and **rising interest rates** may be starting to have an effect. **Jobless claims** have been **steadily edging higher this year** and **some companies** have announced **hiring freezes or layoffs** in recent weeks.


Total Jobs Added in July, by Selected Industries
Private goods-producing
Private service-providing
Public sector
Mining and logging
7,000
Construction
32,000
Manufacturing
30,000
Wholesale trade
10,500
Retail trade
21,600
Transportation and warehousing
20,900
Utilities
400
Information
13,000
Financial activities
13,000
Professional and business services
89,000
Education and health services
122,000
Leisure and hospitality
96,000
Other services
15,000
Government
57,000
Note: Data is preliminary and seasonally adjusted.
Source: U.S. Bureau of Labor Statistics, Employment Situation, August 2022. • Created with Datawrapper

Markets Post Worst First Half of Year in Decades

by Akane Otani – WSJ – Jul. 1, 2022

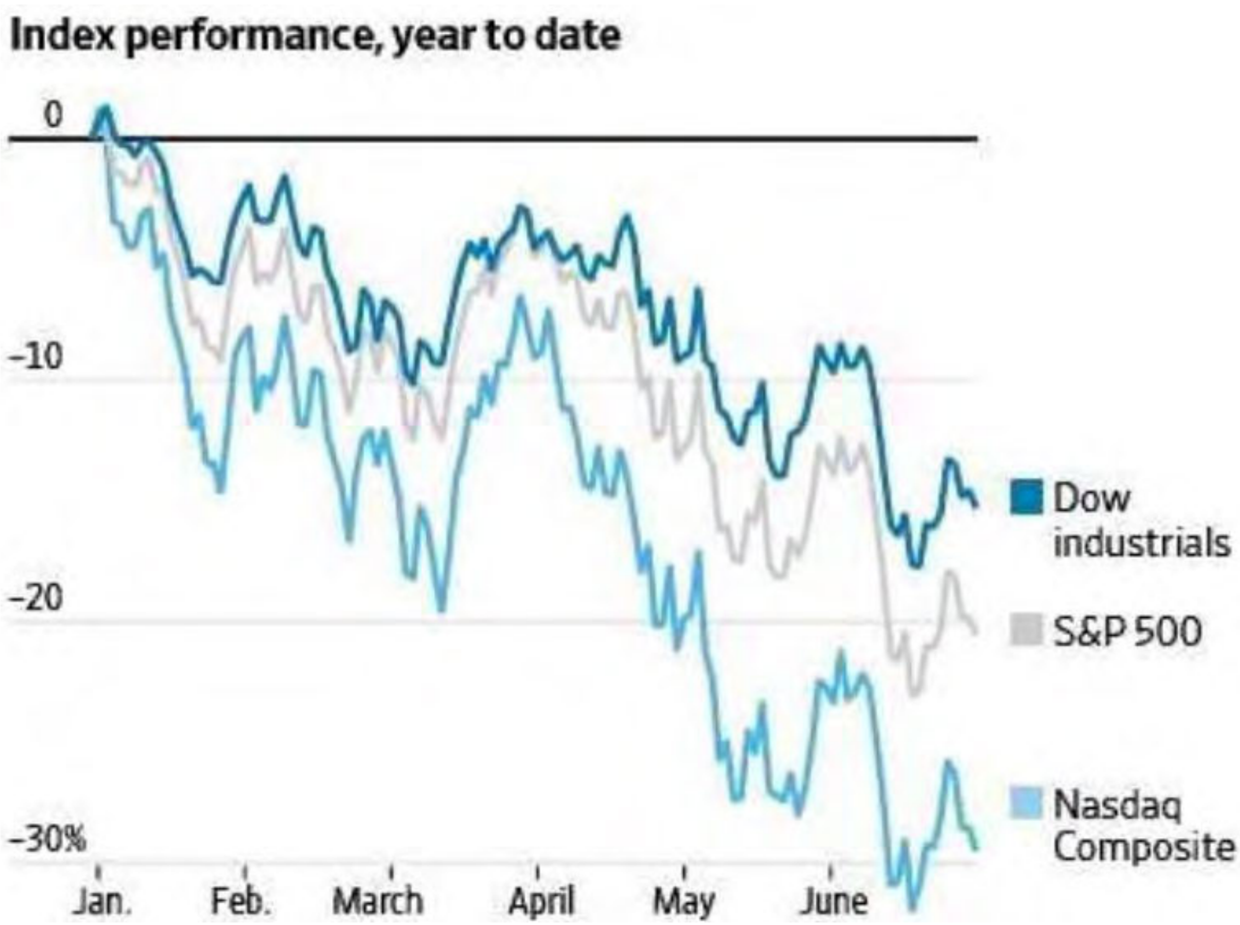
Global markets closed out their most bruising first half of a year in decades, leaving investors bracing for the prospect of further losses.

Accelerating inflation and rising interest rates fueled a months-long rout that left few markets unscathed. The **S&P 500 fell 21% through Thursday**, suffering its **worst first half of a year since 1970**, according to Dow Jones Market Data. The blue-chip Dow Jones Industrial Average lost 15%.

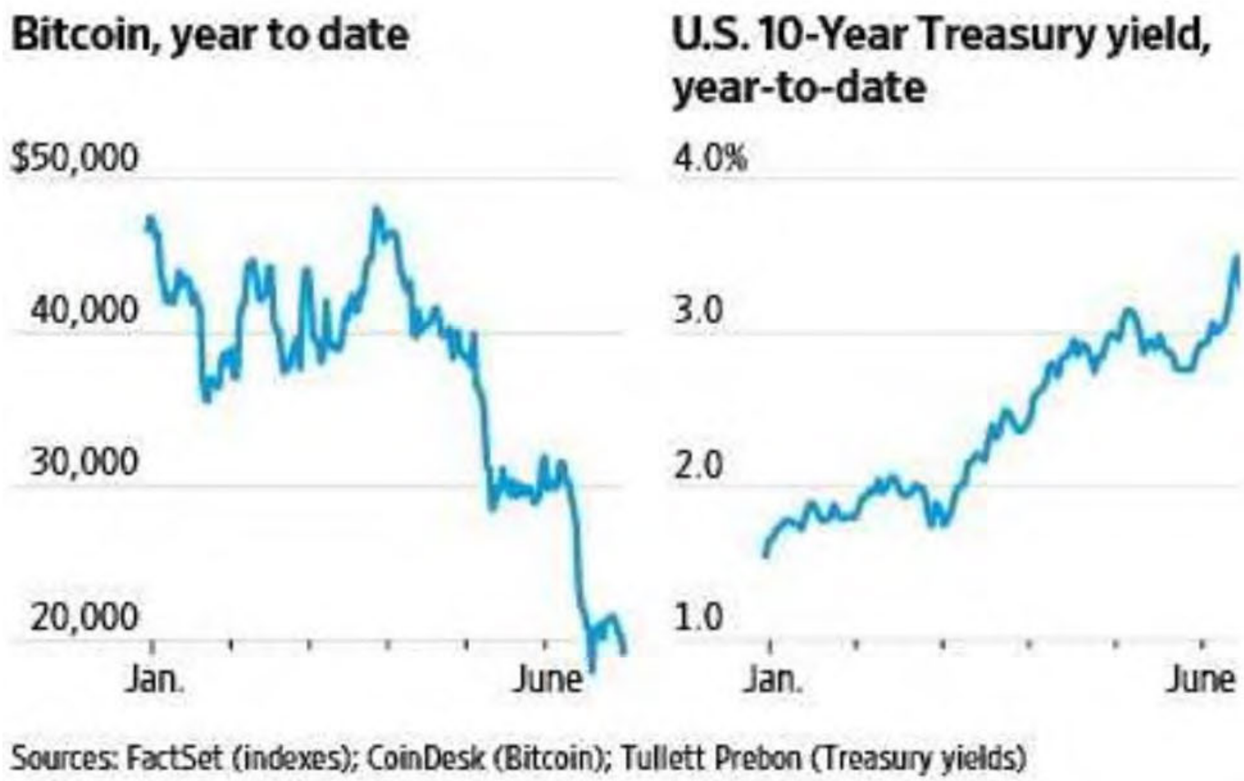
Investment-grade bonds, as measured by the iShares Core U.S. Aggregate Bond exchange-traded fund, **lost 11%** – posting their **worst start to** a **year in history**.

Stocks and bonds in emerging markets declined, hurt by slowing growth. And **cryptocurrencies** came **crashing** down, saddling individual investors and hedge funds alike with steep losses.

About the only thing that rose in the first half was commodities prices. **Oil prices surged above $100 a barrel**, and **U.S. gas prices hit records after** the **Russia-Ukraine war** up-ended imports from **Russia**, the **world's third-largest oil producer**.



Now, investors seem to be in agreement about only one thing: More volatility is ahead. That is because **central banks** from the U.S. to India and New Zealand plan to keep **raising interest rates** to try **to rein in inflation**. The **moves will likely slow down growth, potentially tipping economies into recession** and generating further tumult across markets.



"That's the biggest risk right now – inflation and the Fed," said Katie Nixon, chief investment officer for Northern Trust Wealth Management.

Ms. Nixon said she would be keeping a close eye on economic data to gauge how much rising rates are weighing on growth over the next few months. Her firm has kept money in U.S. stocks, wagering the economy will slow down but avoid a recession. It also put money into companies focused on natural resources, a bet that should pay off if inflation persists for longer than it expects. "You don't want to be whipsawed by the markets," she said.

The good news for investors is that markets haven't always done poorly after suffering big losses in the first half of the year. In fact, history shows they have often done the opposite.

When the S&P 500 has fallen at least 15% the first six months of the year, as it did in 1932, 1939, 1940, 1962 and 1970, it has risen an average of 24% in the second half, according to Dow Jones Market Data.

One reason markets have often snapped back after big pullbacks: Investors have eventually stepped in, wagering prices have fallen too far. Fund managers currently have larger-than-average cash positions, smaller-than average equities positions and a markedly high degree of pessimism about the economy, Bank of America found in its June survey of investors. Those factors, among others, make markets look "painfully oversold" – and thus potentially ripe for a rally, the bank's strategists said in a separate report.

But even those finding buying opportunities these days said they are focusing on specific companies, instead of buying broadly. They concede that the current economic environment – in which inflation is high, borrowing costs are rising and growth is expected to slow – makes it difficult to be enthusiastic about many parts of the market.

Economists surveyed by The Wall Street Journal in June said they saw a **44% probability** of a **recession** in the **U.S. in** the **next 12 months**, compared with 18% in January.

History has shown the Fed has seldom been able to pull off a "soft landing," a scenario in which it slows the economy enough to rein in inflation but avoids tightening monetary policy to the point of causing a recession. The U.S. went into recession four of the last six times the Fed began raising interest rates, according to research from the Federal Reserve Bank of St. Louis that looked at monetary- policy-tightening cycles since the 1980s.

"The runway for the Fed to manage a soft landing is not only narrow but also winding and bumpy," said Lauren Good-win, economist and portfolio strategist at New York Life Investments.

While household spending and corporate balance sheets look relatively strong, it is difficult to see the economy avoiding recession sometime next year, Ms. Goodwin added.

That leaves investors in a quandary. The economy isn't in recession, but many think it could get there in the coming year or so. Investments that many have traditionally turned to during selloffs, like cash, money-market funds and Treasurys, haven't held up as well this year because of inflation.

Investors said much of their outlook for the rest of the year depends on how quickly the Fed is able to contain inflation, and how much the economy slows as a result.

The third quarter started early Friday in Asia. Japan's Nikkei 225 was down 0.9%, Hong Kong's Hang Seng Index was down 0.6%, China's CSI 300 was down 0.1% and South Korea's Kospi was down 0.6%. S&P 500 futures fell 0.7%.

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MDU Resources to Spin Off Construction Materials Business

by Nephele Kirong – S&P Global Market Intelligence – Aug. 4, 2022

MDU Resources Group Inc. is **spinning off** its **construction materials business**, **Knife River Corp**., in a bid to unlock "significant shareholder value" and enhance strategic focus on its regulated utilities, natural gas pipelines and related infrastructure services.

The planned spinoff will result in two independent, publicly traded companies with more flexibility in deploying capital toward specific growth opportunities, MDU Resources said in an Aug. 4 news release.

Knife River provides **construction materials and contracting services**. It generated $293 million of EBITDA in 2021.

MDU Resources shareholders are expected to retain their current MDU Resources stock and receive a pro rata distribution of Knife River shares in a tax-free transaction. The number of shares to be distributed will be determined before **closing**, which is **expected** in **2023**.

The **transaction** is **subject** to customary conditions, including **final approval** by the **MDU Resources board**, receipt of a **tax opinion and**, **if determined advisable**, a **private ruling from** the **IRS**.

"The MDU Resources board believes Knife River is ready to continue its success as a stand-alone public company and take full advantage of anticipated work resulting from federal infrastructure funding," Chairman Dennis Johnson said.

MDU Resources tapped J.P. Morgan Securities LLC and PJT Partners as financial advisers. Wachtell Lipton Rosen & Katz is acting as legal adviser on the transaction.

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Municipal Bonds Increasingly Held by Funds Instead of Individuals

by Heather Gillers – WSJ – Jun. 28, 2022

Share of munis held by individuals falls to 40% in the **first three months** of the year from 46% in 2020, study finds.

The double decker State Route 99 highway tunnel being built in Seattle in 2018.

One factor aggravating volatility in munis this year: **Asset managers' increasing share** of a **$4 trillion market once dominated by buy-and-hold individual investors**.

The **share** of **outstanding municipal bonds held by U.S. households fell to 40%** in the **first three months** of the **year from 46% in 2020**, according to a Municipal Securities Rulemaking Board report scheduled for release Wednesday. The board, a self-regulatory body overseeing the muni market, analyzed Federal Reserve data and determined that the market is shifting from direct ownership of bonds to investment through funds.

The **true amount held outright by buy-and-hold retail investors** through individual brokerage accounts is **likely closer to 20%, because** the **Fed includes** some **Wall Street-managed accounts in** its **household category**. So-called **separately managed accounts** are **run by** an **asset manager on behalf of** a **single investor**. Those **hold** about **18% of munis**, according to Citigroup.

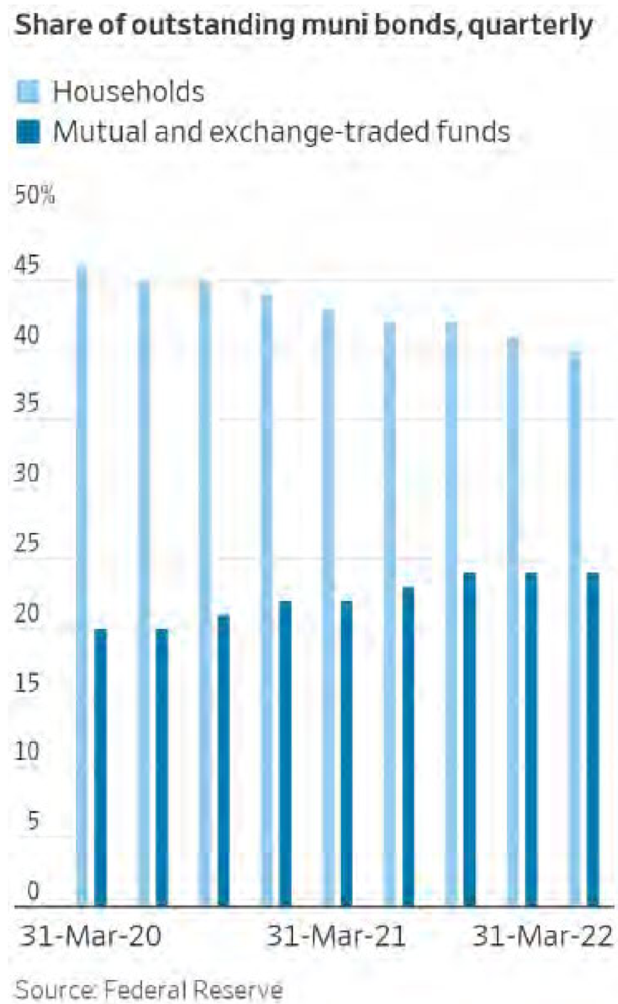
Mutual and exchange-traded funds controlled 24% of munis in the **first quarter** of **2022**, **up from 20%** in **2020**, according to Federal Reserve data.

Wealthier investors are **attracted** to **debt issued by state and local governments because** the **interest** is **typically exempt from federal, and often state**, **taxes**. **Prices** have **slid** for muni debt and across bond markets **this year following aggressive moves** by the **Fed to curb inflation**. The **Bloomberg municipal bond index returned minus 9.31% through Friday**, counting price changes and interest payments, its worst year-to-date performance on record.

Asset managers' increasing control over the market is part of a dynamic aggravating that price drop, analysts said. Investors in mutual and exchange-traded funds can watch their prices fall in real time and cash out easily. Buy-and-hold investors, in contrast, tend to own bonds until maturity, clipping coupons for income.

"I think they probably trade less frequently than financial professionals, whether they be [separately managed accounts] or mutual funds," said John Bagley, the Municipal Securities Rulemaking Board's chief market structure officer and an author on the report.

Investors have **pulled** more than **$80 billion from muni mutual and exchange-traded funds this year though mid-June**, more than in any full calendar year going back to 1992, the 30 years tracked by Refinitiv Lipper. That can force fund managers to sell bonds at unappealing prices to drum up cash for investors.



Mutual funds, exchange-traded funds and separately managed accounts appeal to investors because the oversight of a professional manager makes them more comfortable holding riskier bonds. Those bonds have relatively higher yields, which held particular appeal in the low-yield environment of the past decade.

Some investors also prefer to hold a small share of debt from a diverse pool of borrowers to guard against defaults. Some like the flexibility with which they can get in and out of mutual and exchange-traded funds.

Vanguard Group, **Nuveen** LLC, **Franklin Templeton** and **BlackRock** Inc. were the **managers with** the **largest dollar amount** of **municipal bonds under management** in **2021**, according to Refinitiv Lipper.

The market continues to be dominated by individual investors, even if more of them are investing through accounts controlled by Wall Street money managers. In contrast, only 3% of Treasurys and 1% of corporate bonds are held by U.S. households, the Municipal Securities Rulemaking Board found.

“Even though individual investors are going down, it is still an individual investor market unlike any other market,” Mr. Bagley said. “They have a lot of ways to access it: mutual funds, ETFs, SMAs, individual brokerage accounts. The components that make it up have changed but the overall number has been pretty consistent.”

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NRC Approves Southern's Vogtle Unit 3 for Nuclear Fuel Load, Operation

by Abbie Bennett – S&P Global Market Intelligence – Aug. 3, 2022

The **U.S. Nuclear Regulatory Commission** on Aug. 3 **authorized** Southern Co. **subsidiary** Southern Nuclear Operating Co. Inc. to **load nuclear fuel** and **begin operation** at the Alvin W. **Vogtle Nuclear Plant** in **Georgia**.

Unit 3 of the two-unit Vogtle expansion project, **long plagued by delays** and **cost overruns**, is the first reactor to reach this point in the NRC combined license process, the agency said in its announcement. Southern subsidiary Georgia Power Co. recently informed the NRC that it had completed the inspections, tests, analyses and acceptance criteria needed to show that unit 3 can begin safe operations.

"This is the first time we've authorized a reactor's initial startup through our Part 52 licensing process," said Andrea Veil, director of the NRC's Office of Nuclear Reactor Regulation. "Before authorization, we independently verified that Vogtle unit 3 has been properly built and will protect public health and safety when it transitions to operation. Our resident inspectors at Vogtle will keep a close eye on unit 3 as the fuel load and startup testing move forward. We're focused on safety so the country can use Vogtle's additional carbon-free electricity. We will maintain this focus as we license the next generation of new reactors."

The **NRC's** decision **moved unit 3 out of the construction reactor oversight program** and **into** the **operating reactor oversight** process. **Vogtle unit 4 remains under construction**.

"Today's finding by the NRC helps ensure we have met our commitment to building Vogtle 3 and 4 with the highest safety and quality standards," Georgia Power Chairman, President and CEO Chris Womack said in a statement Aug. 3. "These new units remain a strong long-term investment for this state and, once operating, are expected to provide customers with a reliable and resilient, clean, emission-free source of energy for the next 60 to 80 years."

The team on-site is making final preparations for unit 3 fuel load, initial startup testing and bringing the reactor online. This will be followed by several months of startup testing and operations, designed to show the integrated operation of the primary coolant system and steam supply system at design temperature and pressure with fuel inside the reactor. Operators will also bring the plant from cold shutdown to initial criticality, synchronize unit 3 to the grid and systematically raise power to 100%, according to Georgia Power.

Units 3 and 4 are **expected to enter service** in the **first and fourth quarters** of **2023**, **respectively**, with **fuel load** for **unit 3 projected** for **late October 2022**. Timely fuel load for unit 3 and startup, along with "sustained improvement" in unit 4 electrical production, are both necessary for unit 4 to hit its projected December 2023 in-service date, Southern executives said July 28 on a second-quarter earnings call.

Significant US Growth Slowdown Ahead, But Recession Could Still Be Avoided

Moody's Investors Service – Jul. 28, 2022

We lowered our **US real GDP growth** forecast to **2.2% this year** and **1.6% in 2023**

We have lowered our 2022-23 economic growth forecasts the US (Aaa stable) to incorporate the effect of Federal Reserve monetary policy becoming increasingly restrictive to tame surging inflation. The US macroeconomic cycle is at an inflection point with a downshift in growth clearly ahead, and much will depend on factors beyond the Fed's control, such as supply issues and energy prices.

US real GDP growth is set to slow. We now expect US real GDP growth of 2.1% in 2022 and 1.3% in 2023, down from our May forecasts of 2.8% in 2022 and 2.3% in 2023. Stubbornly **high inflation** is being **met with tighter monetary and financial conditions**, and **economic growth will weaken**. We expect the unemployment rate to rise to slightly above 4.0% in 2023 from the current low rate of 3.6%, owing to a combination of slower hiring and rising labor force participation as more workers seek re-employment.

Policy decisions are made more challenging by lags in economic data and policy transmission. It will be tricky to navigate to an equilibrium where inflation falls but economic activity does not slip into recession. The US economy remains fundamentally strong currently, but **macroeconomic volatility will persist for at least another year**, **injecting large swings in key macroeconomic indicators, complicating the assessment of economic conditions**.

Inflation will remain elevated this year and into next year. Our forecasts assume that tighter financial conditions, combined with the ongoing inflationary shock, will limit additional consumer spending and interest-sensitive investment activity over the next year. Inflation will remain above targets this year, but softening demand and some improvements on the supply side will steadily drive inflation lower by end 2023.

Downside risks are high but prolonged stagflation can be avoided. There are two main differences that set the current US economic environment apart from that of the 1970s: (1) the **unemployment rate today remains at record lows** and **economic activity is far from stagnant**; and (2) there has been a paradigm shift since the 1970s in understanding the optimal monetary policy response to tackle business cycle fluctuations. **Lessons learned from the 1970s** are the **reason** why **today's monetary policy framework is credible** and effective, and **why** the **Fed** is **tightening aggressively**.

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Stocks Often Don't Hit Bottom Until Fed Shifts Back to Easing

by Akane Otani – WSJ – Jun. 21, 2022

Another week of whipsaw stock trading has many investors wondering how much further markets will fall.

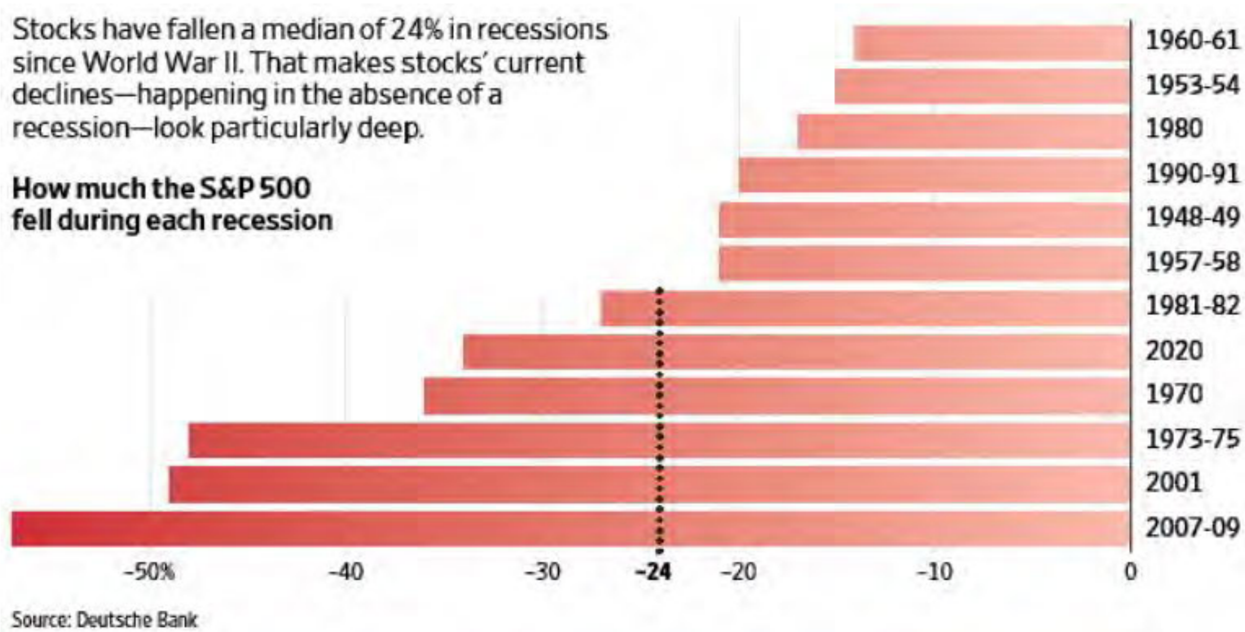
If history is any guide, the selloff might still be in its early stages.

Investors have often blamed the Federal Reserve for market routs. It turns out the Fed has often had a hand in market turnarounds, too. **Going back to 1950**, **the S&P 500 has sold off at least 15% on 17 occasions**, according to research from Vickie Chang, a global markets strategist at Goldman Sachs Group Inc. On **11 of those** 17 occasions, the **stock market** managed to **bottom** out **only around** the **time** the **Fed shifted toward loosening monetary policy again**.

Getting to that point might be painful. The **S&P 500** has fallen 23% in 2022, marking its **worst start to a year since 1932**. The index declined 5.8% last week, its biggest decline since the pandemic-fueled selloff of March 2020.

And the **Fed** has **only** just **gotten started**. **After approving** its **largest interest-rate increase since 1994** on Wednesday, the **central bank signaled** that it **intends** to **raise rates several more times this year** so it can **tamp down inflation**.

Tightening monetary policy, combined with **inflation running at** a **four-decade high**, has many investors fearful that the economy might go into a downturn. Data on retail sales, consumer sentiment, home construction and factory activity have all shown significant weakening in recent weeks. While corporate earnings are strong now, analysts expect they will come under pressure in the second half of the year. A total of 417 S&P 500 companies mentioned inflation on their earnings calls for the first quarter, the highest number going back to 2010, according to FactSet.



This week, investors will be parsing data including existing- home sales, consumer sentiment and new-home sales to gauge the economy's trajectory. U.S. markets week closed Monday for Juneteenth.

"I don't think the rate of the decline in the market will continue at this pace, but the idea that we're approaching the bottom – that's really hard to come up with," said David Donabedian, chief investment officer of CIBC Private Wealth US.

Mr. Donabedian said he has discouraged clients from trying to "buy the dip," or to buy shares on discount with the expectation that the market will turn around soon. Even after a punishing selloff, stocks still don't look cheap, he said. And earnings forecasts still look too optimistic, he said.

The S&P 500 is trading at 15.4 times its next 12 months of expected earnings, according to FactSet, just a hair below its 15-year average of 15.7. Analysts currently still expect S&P 500 companies to report double-digit percentage earnings growth for the third and fourth quarters, according to FactSet.

This week, traders will be parsing data including existing-home sales, consumer sentiment and new-home sales.

Other investors said they are staying wary of the possibility that the Fed might have to act even more aggressively, should policy makers be surprised by another unexpectedly high inflation reading.

The **University of Michigan's consumer-sentiment survey**, released earlier in the month, showed that **households expect inflation** to **run at** a **3.3% pace five years from now**, **up from 3% in May**. That marked the first increase since January. Separately, the **Labor Department's consumer-price index rose 8.6% in May from** the **same month a year ago**, the **fastest increase since 1981**.

"Our feeling is that if the next inflation figure is very high again, the Fed could [raise rates] even more sharply," said Charles-Henry Monchau, chief investment officer at Syz Bank, in emailed comments. That could put further pressure on risky assets such as stocks, he said.

When the Fed began raising interest rates again this year, it said it was hoping to pull off a soft landing, a scenario in which it slows the economy enough to rein in inflation but not so much that it triggers a recession.

Within recent weeks, many investors and analysts have become increasingly pessimistic that the Fed will be able to pull that off.

Data have already shown signs of economic activity cooling. As rate increases further raise the cost of borrowing for consumers and businesses, it is difficult to envision a way in which the Fed can avoid a downturn, many analysts say.

The Fed's moves "raise the risk of a recession starting this year or early next year and raises the risk frankly that they're not going to be able to keep raising rates that long," David Kelly, chief global strategist at J.P. Morgan Asset Management, said on a conference call on Wednesday.

"I wouldn't be surprised if within a year, we're having a meeting where the Fed is considering cutting rates," he said.

Unsurprisingly, stocks typically don't do well during recessions. The S& P 500 has fallen a median of 24% during recessions going back to 1946, according to research from Deutsche Bank.

"If we don't get a recession, we are getting close to extreme territory," Deutsche Bank strategist Jim Reid wrote in a note.

The silver lining for investors is that, when the Fed begins to shift toward easing monetary policy, markets have historically responded positively and quickly – especially if the primary cause of their slide was related to central-bank policy, according to Goldman Sachs's analysis.

What no one is sure of is when exactly the Fed will shift gears, and how much more pressure the economy might come under in the meantime.

"I expect the summer to be very choppy," said Nancy Tengler, chief investment officer at Laffer Tengler Investments.

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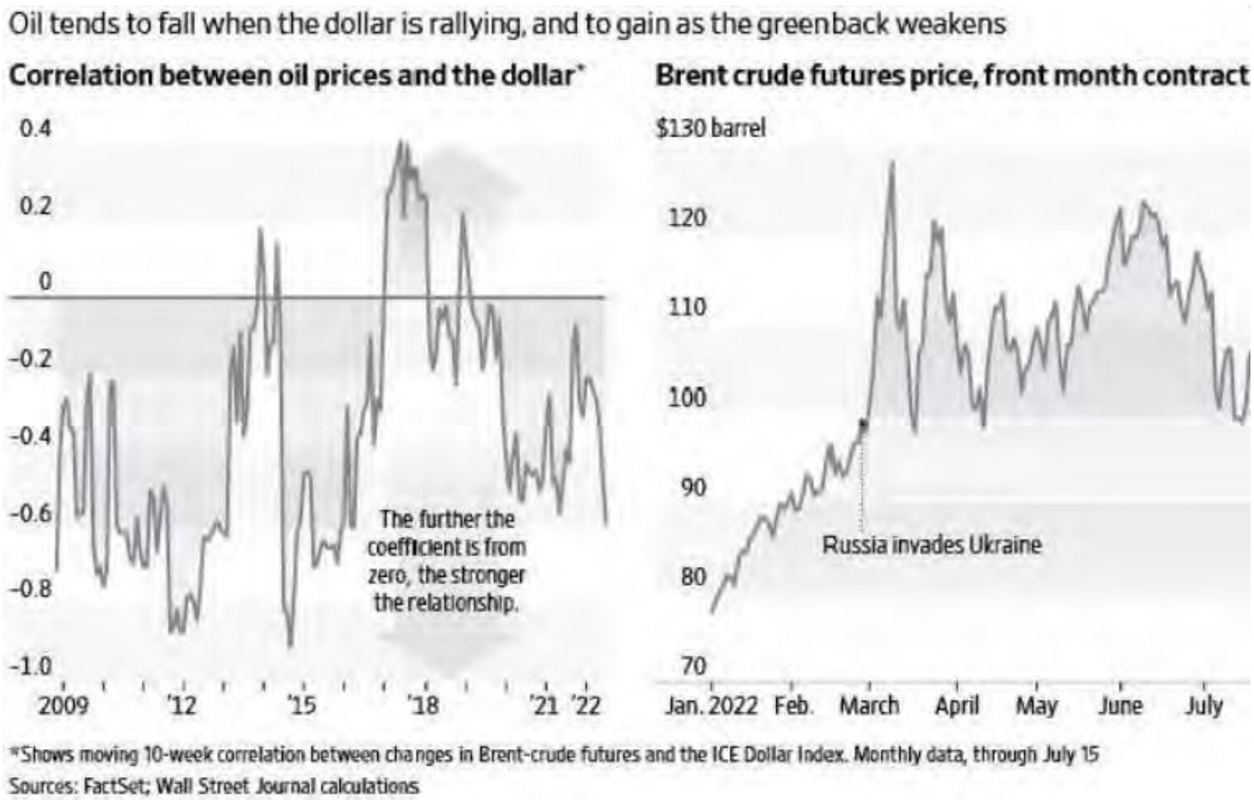
Strong Dollar Sparks Pullback in Global Commodities Markets

by Yusuf Khan and Joe Wallace – WSJ – Jul. 20, 2022



If the dynamic holds and commodity prices remain under pressure, that could help tame inflation and spare the Fed from having to raise interest rates so quickly and so far that the U.S. economy falls into a recession.

Consumers are already getting some relief. The commodity selloff is pulling down gasoline prices at the pump and has some investors hoping that consumer-price inflation in the U.S. peaked in June.

Data on car usage and air traffic give few indications that demand for fuel is taking a hit in major importers such as China and India, said Damien Courvalin, head of energy research at Goldman Sachs Group. But that is bound to change as higher prices take a toll on consumers, he said.

The bank estimates that the dollar's strength has boosted retail fuel prices in countries such as India by the equivalent of $10 a barrel. A shortage of refining capacity adds an extra $15 a barrel, Goldman says.

The International Energy Agency this month said the dollar's strength, combined with record prices for refined fuels, is likely to weigh on oil demand in emerging markets. When the price of Brent crude peaked in early June, they were up 59% in dollar terms.

But they were up by two-thirds in terms of China's yuan and 85% measured in Japanese yen.

A **stronger dollar** isn't just **adding to** the **cost of buying raw materials outside** the **U.S.** It is also likely to encourage non-American commodity producers to sell down inventories, since their earnings are worth more when converted into domestic currencies. In one sign of this, supplies of coffee have risen in Cameroon.

The strong dollar is making it difficult for some countries to afford imports. For example, in Argentina, a shortage of the U.S. currency has led to fewer import licenses for coffee being issued by the government, said Carlos Mera, an analyst at Rabobank.

Commodity and currency markets have a **complex relationship**. **Historically**, **raw-material prices** have been **negatively correlated to** the **U.S. currency**, meaning they have zigged as the dollar has zagged.

That is not just because a **stronger greenback crimps demand**. For **copper** and **grains**, **labor** and **other inputs** are **mostly paid in local currencies**. **Production costs**, therefore, **decline when currencies such as Chile's peso** or the **Canadian dollar weaken**.

For oil, the picture has gotten more complicated in recent years after the shale revolution turned the U.S. into a major energy exporter, and as oil-producing countries in the Middle East began to plow more of their petrodollars into U.S. assets. In the past year, the recovery in the world economy from pandemic restrictions sent oil prices higher just as the dollar took off.

The **negative relationship between oil prices and** the **dollar** has reasserted itself. Brent crude has fallen 14% from its June 8 high to $106 a barrel. In that time, the WSJ Dollar Index has added 3.8%.

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The Supply Chain, Explained

by Willy Shih – WSJ – Aug 1, 2022

Dr. Shih is the Robert and Jane Cizik professor of management practice at Harvard Business School.

Seven principles you should understand:

Three years ago, very few people thought about supply chains. “Where did that product come from?” I used to ask my students. “I got it at Amazon,” was often the answer. “No! How did it get to Amazon?” was my reply, which often was met with a shrug.

Now that so many supply chains are a mess, people are paying a lot more attention.

Supply chains are essentially networks that link producers to consumers, often with dozens of steps along the way. T he core job of supply chains is to match supply with demand, and when things are going well, we take them for granted. But as we’ve seen in the past 2½ years, they can break down under stress.

As a professor who teaches operations management, I tell M.B.A. students they can get their heads around the supply chain, and the turmoil we’re seeing, by understanding seven basic principles:

- Supply chains have more moving parts and layers than you probably imagine. Think of supply chains as having **two phases**: a **production side**, where final assembly of a product takes place, and a **distribution side**, where it gets to the buyer.

The production side can be incredibly complex. That's because some products have lots of parts – 3,000 or 4,000 for a smartphone, for instance, and maybe 30,000 for a typical gasoline- powered car.

That's where the layers come in. With the technological sophistication found in so many products, it's **impossible for one company** to **make everything** by **itself**. Instead, companies turn to specialist suppliers to provide components. For example, a notebook computer will use different companies to make the microprocessor chip, memory chips, display screen, keyboard, disk drive, battery, charger and more.

Companies end up with several tiers of suppliers, like a layer cake. Tier-one firms supply them directly, tier twos supply tier ones, tier threes supply tier twos, and so on. Most companies don't know who is beyond their second tier. That's partly because there are so many – McKinsey estimates the average auto maker has 250 tier-one suppliers and 18,000 suppliers total.

That explains the first big problem we saw at the beginning of the pandemic: Lower-tier suppliers might have shut down and the manufacturer wouldn't know for a while until its tier one couldn't deliver. You only have to be missing one part, and you can't finish assembling your pickup truck, your game console or your freezer.

On the distribution side, a simple supply chain might have steps that connect a manufacturer to a retailer, passing through a trucking link on the way to the retailer's distribution center, and then on to the store. But if the factory is far away, there could be perhaps a dozen steps along the way.

Our supply-chain woes of the past few years have occurred both on the product side, because companies ran out of parts, and on the distribution side, where shipping companies ran into bottlenecks due to such factors as labor shortages and congested ports.

- **Sudden spikes in demand can be easily misread**. Consumers signal demand by buying things, and companies in the chain respond by placing orders upstream. But when there are many companies in a chain, the signals can run amok.

Demand forecasting is often based on order histories – what did the customer buy last month? When demand is stable, supply chains just chug along. But when you get a sudden spike in demand (as happened often during the pandemic), things can go haywire.

The problem is the spikes are often misinterpreted as fundamental shifts. The retailer says, "These are hot sellers, let me increase my order." Then the product planner at the manufacturer says, "This is a hit. Let's order more so we don't lose sales." Everybody in the chain turns optimistic and tries to prepare for upside, and it's easy for the true demand signal going up the chain to get exaggerated. By the time the orders get to the factory, the demand signal may have been amplified several-fold.

Eventually, that demand signal gets turned into product that starts making it back down the chain. That's about the time people start to realize that perhaps they ordered too much, so they slash their orders. This is called the "**bullwhip effect**," because the amplification and oscillations in product volumes moving along the chain look like the cracking of a bullwhip. We saw it in toilet paper and exercise bikes, and we are seeing it right now in many products such as bedding and clothing.

- **Because demand is hard to predict**, man**y companies turned to just-in-time production**. Which can **work fine, sometimes**. The whole motivation for the just-in-time production system that so many companies used before the pandemic was that it was so hard to know in advance what the demand for any particular product would be. So let's make only exactly what we need when we need it. This philosophy extends to carrying minimal inventory of parts and raw materials delivered just in time, because **if there is a defect** in one of those **parts** in the pipeline, there are **relatively few** that **have to be reworked or repaired**.

This **works best when suppliers and factories** are **fairly close**, less than an hour or two apart, as it was when it was **originally created by Toyota**, and as is often found in industrial parks in China. Companies can schedule daily deliveries, or even every few hours. This means lean supply chains with better quality and less money tied up in inventory, leading to lower costs and better financial performance. The problem comes when manufacturers extend the practice to far-flung networks of suppliers around the world. Scheduling deliveries for exactly when you need it becomes much more complex. But things really fall apart – as they did during the **pandemic** – when demand spikes, **bottlenecks** start **disrupting international cargo** shipments **and parts stop showing up in time**. That's why we have seen **huge** increases in auto parts moving via air cargo, something that was previously unthinkable because of the cost.

You would only do this if the parts wouldn't otherwise arrive just in time.

The experience during the pandemic explains why **more companies** are **shifting away from just in time** and **adopting** a **just in case philosophy** of **carrying** more **inventory**. As we'll see, that **can work fine** – **under certain conditions**.

- **Ordering more than you actually need makes shortages worse**.

Typically, a retailer or manufacturer only orders as much as they think they can sell or consume until the next cycle begins. But sometimes a hot seller comes along, or you hear a part is going to be in short supply, so you decide to order extra – just in case.

In many sectors over the past year, firms that use electronic components in their products have been ordering up to twice what they think they actually need. This has two predictable consequences: At first, it makes those products or parts that are in short supply even harder to get. And second, companies will someday likely be stuck with a lot of excess inventory, and will need to cut prices to unload it, or spend a lot of money carrying it.

The answer isn't to abandon just-in-case production. It's a **balance**. **Just in time still makes sense when you have local suppliers** and everyone is communicating, or to **buffer distant supp**liers **with** some **just-in-case inventory**.

- The **longer the distribution chain**, the **more susceptible it is to disruption**. To understand why longer chains are more problematic, I often ask people how many have endured a kitchen remodeling project, and did it go according to schedule? The answer is almost always no, and the reason is because of the structure of the sequence of work. One step – say, removing the old cabinets and fixtures – must be completed before the next step can begin, so a delay in a single step delays the whole project.

This is called the "**parade of trades**" **problem**, and longer chains of logistics steps suffer more than short ones. You need smooth handoffs so when the container ship arrives at the terminal, a truck can pick up the container, and when the truck arrives at the warehouse, it can unload and bring the empty container back. Before the pandemic each of these steps happened with fairly predictable timing. When the pandemic hit and labor shortages or other bottlenecks started showing up, big delays at one or two steps rippled across the whole chain.

- **Congestion removes capacity from** the **system**. When we encounter a traffic jam on the freeway, we easily recognize the extra time it will take us to get to our destination. It's the same thing with the supply chain: The more vehicles in the chain, the more backed up things get, and the less stuff gets moved each day.

On the eastbound trans-Pacific route over the past two years, container lines assigned more ships and more containers to the trade lane because of high demand from U.S. consumers. But the increase in the number of ships and containers paradoxically meant fewer ships per hour made it to the ports because of the increased congestion.

- **Bottlenecks are hard to spot** because so few can see the whole picture. People at different links might only see what is immediately upstream or downstream from them. So when there is something really visible like 100 ships waiting to unload, it's easy to think that the problem is at the Los Angeles/Long Beach ports.

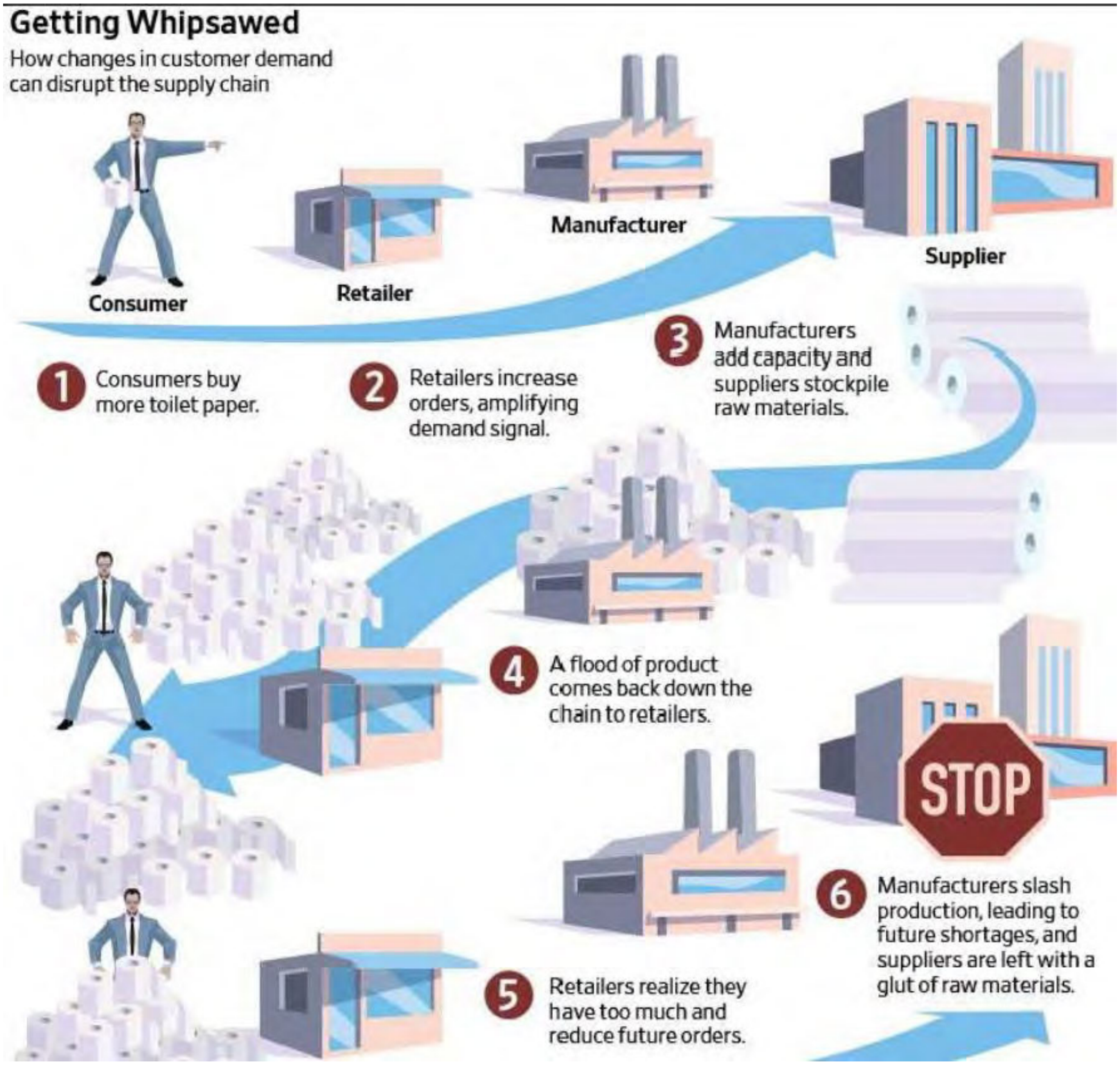
But that wasn't really where the bottleneck was. Rather, it was at distribution centers closer to the consumer. Trying to increase ports' capacity by running them 24 hours a day didn't help, because the problem was there was no place for the containers to go. A lot of warehouses were and are still chockablock with inventory, so they have difficulty unloading containers. That backs up the whole chain – all the way to the ships sitting at sea.

These seven principles offer a way to look at how the supply chain does – and more recently, doesn't – work. The question now is this: What's the outlook for getting back to normal?

That largely depends on how much over-ordering went on in response to real and perceived shortages. The demand signal went through the roof during the pandemic, but the amount of oversupply will vary from product to product.

Here's what's **likely**, though: The **overshoots**, caused by all the layers, misread spikes in demand, congestion and bottlenecks, will be **followed by undershoots**, which will **then** drive **more overshoots** (**albeit smaller) until** it **evens out**. Ideally, companies will start to use just-incase production out of reasonable caution rather than fear. And hopefully, they will have learned some valuable lessons along the way.

Supply chains can break down under stress – and the **more complex** they are, the **more likely** they are **to have problems**.


Getting Whipsawed
How changes in customer demand can disrupt the supply chain
Consumer
Retailer
Manufacturer
Supplier
1 Consumers buy more toilet paper.
2 Retailers increase orders, amplifying demand signal.
3 Manufacturers add capacity and suppliers stockpile raw materials.
4 A flood of product comes back down the chain to retailers.
5 Retailers realize they have too much and reduce future orders.
STOP
6 Manufacturers slash production, leading to future shortages, and suppliers are left with a glut of raw materials.

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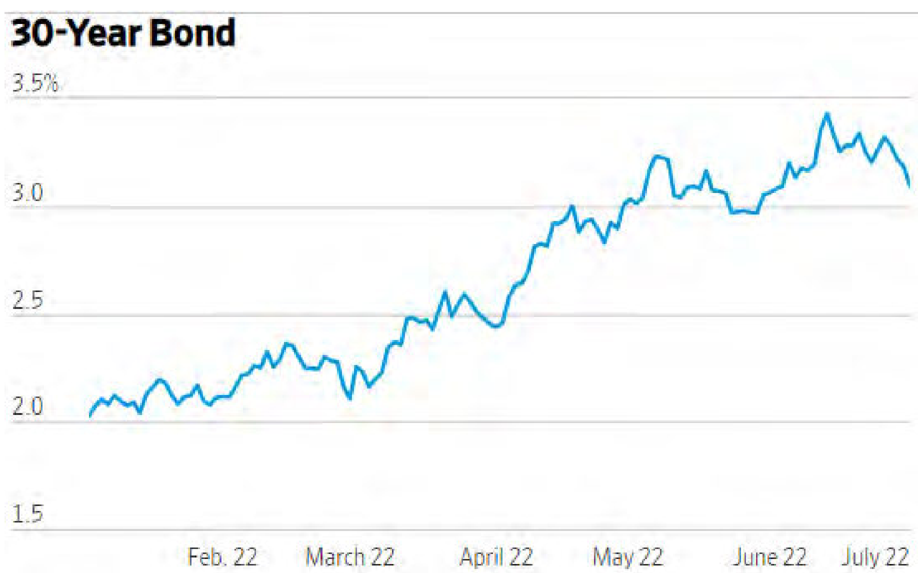
Treasury Rally Pushes Yield Below 3%

by Matt Grossman – WSJ – Jul. 1, 2022

Investors bought government bonds on Thursday to close out a turbulent quarter of trading, **sending** the **yield** on the benchmark **10-year U.S. Treasury note back below 3%** as concerns about slowing economic growth mounted.

The yield on the 10-year note fell to 2.973% after **settling** on **Wednesday** at **3.091%**. A **bond's yield falls when** its **price rises**.



After mounting one of its fastest increases in history to start 2022, the **10-year yield** has in **recent weeks retreated from** an end-of-day high of **3.482%** reached on **June 14**, reflecting traders' dimming views about the economy.

Fears of an economic downturn have drawn more investors toward the guaranteed returns offered by ultra-safe Treasury bonds, reversing some of the rapid gains yields saw earlier this year.

Treasury yields largely **reflect expectations** for **short-term rates set by** the **Federal Reserve**.

As **anxiety about growth mounts**, investors are re-evaluating how they expect the Fed to steer the economy, with some now p o n d e r i n g whether slowing growth may lead the central bank to ease away from aggressive interest-rate increases sooner than expected.

Economic data released this week underscored that thinking.

A Commerce Department report showed that **consumer-spending growth cooled** in **May to 0.2%,** the **smallest monthly gain this year**.

Estimates of first**-quarter economic growth got** a **downward revision**, with statisticians reporting that personal consumption was likely weaker than previously thought.

Labor markets remain strong, but **slowing home sales** and **record-low consumer sentiment** have added to concerns that **soaring prices for necessities** like **gasoline** and **food** are **catching up with household budgets**.

"You're starting to build a case that the consumer is slowing down," said Andrew Brenner, head of international fixed income at National Alliance Securities.

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Up, Up, Up

by J.J. McCorvey, Ayse Kelce and Brian Whitton – WSJ – Jul, 16, 2022

Inflation just hit a four-decade high. Mining the consumer price index reveals some nuance. A guide to what's up – and what comes next.

Chicken – UP 19%

The price of chicken has been climbing each month, all year. Higher energy and labor costs are hitting producers.

Airline Fares – UP 34%

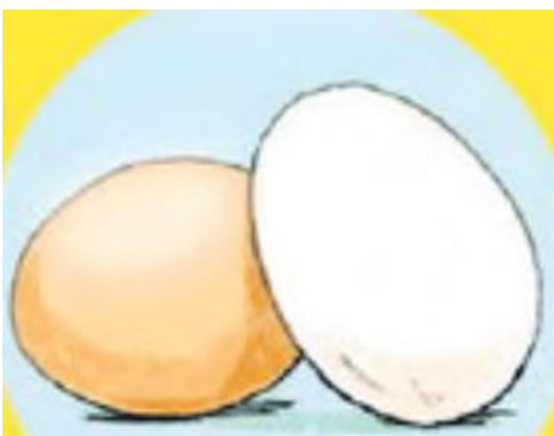
Summer crowds are returning to near pre-pandemic levels as demand, limited supply and fuel prices have lifted fares.

Butter – UP 21%

A drop in milk production whipped up butter prices, making it harder to trim the fat from grocery budgets.

Gas, Groceries and Housing.

The three areas where Americans spend the most are more expensive than they were a year ago.



Eggs – UP 33%

The higher cost of chicken feed came first. Then an avian flu compounded the problem.

Regular Unleaded – UP 61%

Gas drove much of the overall inflation increase. But prices began to cool in July.

Men's Suits – UP 25%

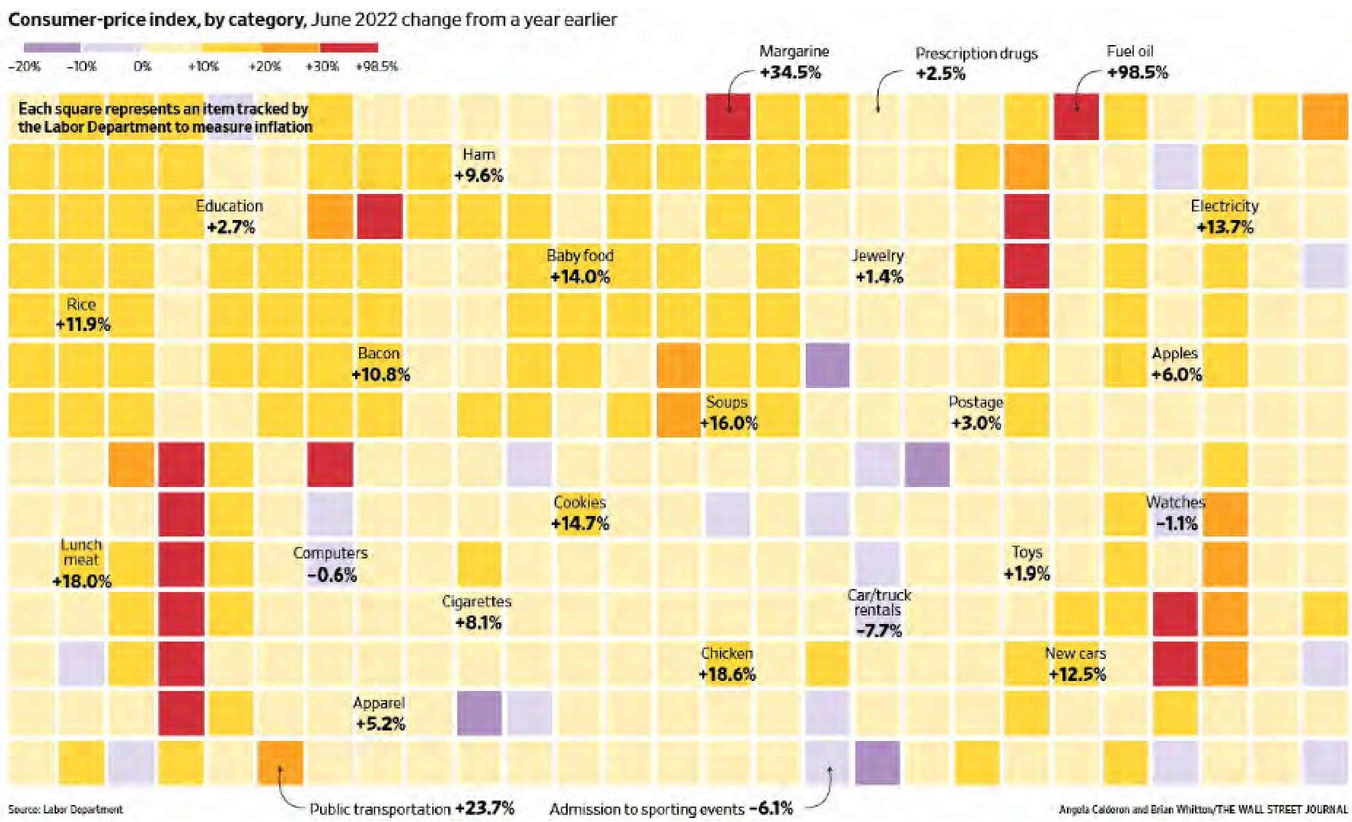
Staffing challenges and labor costs are driving up prices on items like haircuts and suits.

Inflation is at its highest level in more than four decades after rising to 9.1% in June, which means the majority of Americans are experiencing the first sustained rise in prices of their adult lives. It's eating into paychecks, savings and sense of stability.

To see the particulars of what rising inflation means for budgets and daily spending decisions, it pays to drill down into the numbers. To make this easier, The Wall Street Journal created an inflation tracker to explore more than 100,000 data points the Bureau of Labor Statistics collects each month on the price of everything from toys to trucks and how each changed over time.

Sticker shock is widespread. But not everything is going up, and there are still bargains to be had.

The True Costs of Inflation



Start with energy, where Americans are getting pinched at the moment. Yet another spike in the cost of **gasoline** and **household utility bills** last month sent consumer energy prices 41.6% higher than June of last year, an index that includes gasoline, fuel oil, electricity, and natural gas. This was the biggest jump since 1980, when the U.S. economy was reeling from an oil shock following the Iranian Revolution.

Prices for gasoline alone rose 11.2% in June from the previous month, due in part to high crude prices and shortage of refinery capacity. Natural gas for home use rose 8.2% on the month, while electricity increased 1.7%, as the **Ukraine war** roiled natural-gas supplies and summer air-conditioning use swelled.

A surge in energy prices can ripple throughout the economy, economists say, affecting everything from industrial production to shipping. It affects the gasoline it takes to truck tomatoes to the grocery store, the petroleum used to create the plastic that keeps those tomatoes fresh and the natural gas used to make the fertilizer in which the crops were grown.

Low- and middle-income families are most vulnerable to these fluctuations, according to an analysis of Bureau of Labor Statistics June data conducted by the National Energy Assistance Directors Association. **Lower-income households** making about $26,400 on average are **on track** this year to **spend 25.7% of** their **income** on **gas and home energy bills**, **up from the 20.3%** that group spent **in 2020**. For middle-income households making an average of about $65,700, those expenses are on track to account for 12.3% of their income, up from 9.5% in 2020. The highest income group – with average earnings of about $241,300 – will spend 4.7% of their income on such costs, compared with 3.7% two years ago.

The price of oil has fallen in recent weeks, sending the average price of a gallon of gasoline to $4.58, according to AAA. These drops weren't reflected in June government statistics about inflation.

That shift could have broader implications if prices continue to drop.

What else is going up?

The **soaring cost of energy affects groceries** as **costs** rise **to transport food**, **store it and keep it fresh**.

The war in Ukraine also tightened supplies around the world, adding more pressure to prices.

Consider what happened to milk. The price of dairy products soared 13.5% in the past year as milk production declined. Some analysts say this happened because dairy farmers concerned about the costs of transportation took quick profits by slaughtering cows instead of shipping them to other farms where they could be milked for years.

"We have **100,000 fewer cows** in the **milking** herd **this year versus last year**," said Phil Plourd, president of Blimling and Associates, a dairy market analysis and consulting firm. "That will get resolved because prices are high and margins are getting better," he added, "but it just doesn't happen overnight."

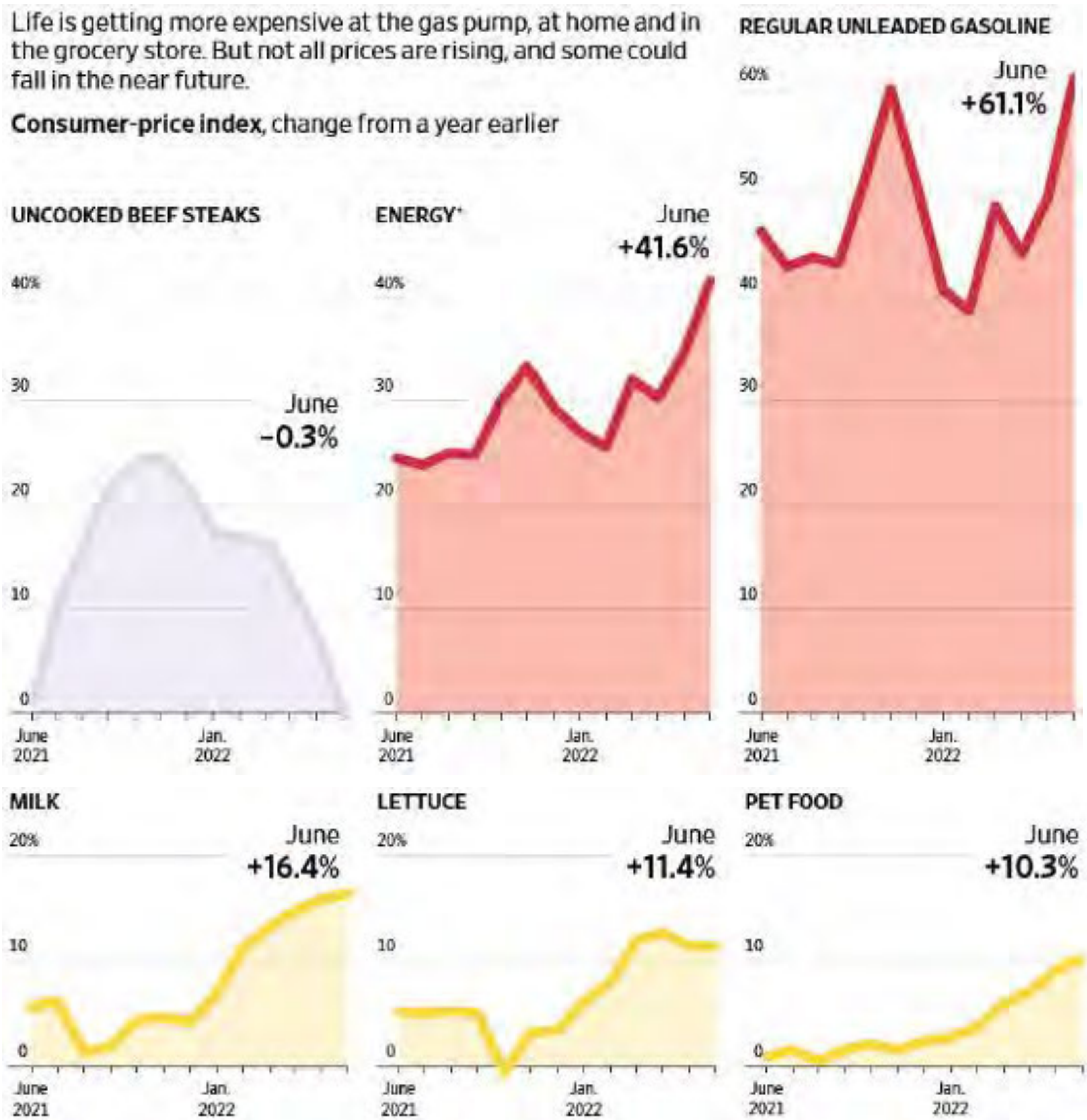
The **price of butter** also **jumped 21.3%** in the **past year**, due in part to the **declining milk production**.

Prices are returning to their historical average after dropping during the earlier stages of the pandemic as demand for restaurant dining fell, according to Peter Vitaliano, chief economist of National Milk Producers Federation.

The average American consumed the equivalent of 25 sticks during 2020, according to the USDA.

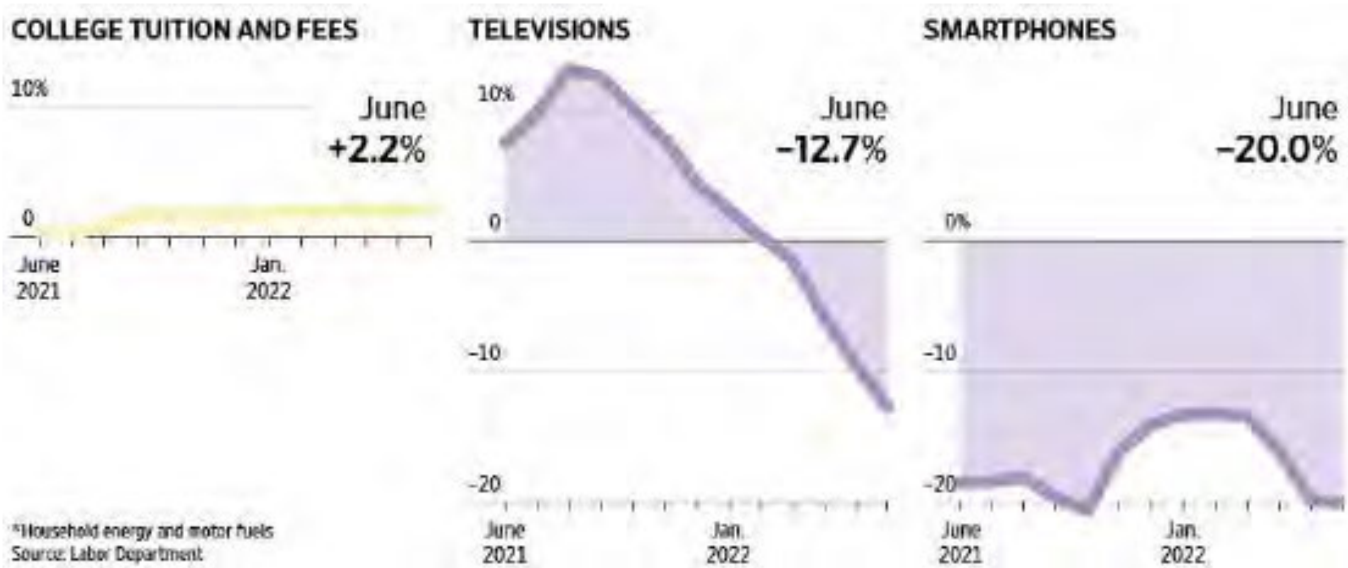
Elsewhere in the grocery aisles, **poultry and egg** prices are **up 17.3%** and **33.1%**, **respectively**. **Avian influenza**, also known as **bird flu**, contributed to those increases. In the produce section, **droughts** helped account for an **11.4% increase** in the price of **lettuce**, **9.3%** for **citrus** and **6.57%** for **bananas**.

Sugar and sweets are **up 9.4%.**



What's getting cheaper?

Some items are getting less expensive, illustrating that inflation isn't sending all prices up.



Smartphones and TVs are **considerably** cheaper **than** a **year ago** thanks to **aggressive discounting by retailers**. Roughly **71%** of **TVs** purchased in the U.S. from January to April of this year were **sold at** a **promotional discount**, according to the NPD Group. Last year that figure was 18%. **Smartphones** are also **20% less expensive**.

The price drops are a function of declining demand. Many consumers loaded up on TVs, computers and other electronics earlier in the pandemic, and interest in purchasing more of these items has since cooled, said Ben Arnold, consumer technology analyst for NPD Group. Some mobile carriers are offering favorable device trade-ins and discounts, said Nabila Popal, research director at IDC within its consumer devices team.

“It is the massive trade-in offers from carriers these days, up to $1,000 for even a damaged phone, that make new phones practically free for the consumer,” said Ms. Popal. “I don’t see these kinds of deals anywhere else in the world.”

Other price drops can be found while boarding a ship, where fares are down, or attending a sporting event, where tickets are cheaper.

Car and truck rentals are also more affordable than they were a year ago thanks to a flow of new inventory that allowed agencies to ease rental terms, said Ivan Drury, senior manager of insights at Edmunds. com.

What hasn’t changed

Some prices haven’t budged much over the past year. **Funeral expenses**, **jewelry** prices, **internet services** and **alcoholic beverages** served at home showed only slight increases.

State motor-vehicle registration and license fees also increased just 0.7% in the past year. “Those prices don’t really move with the state of the economy. They’re fairly rigid," said Laura Rosner-Warburton, senior economist at MacroPolicy Perspectives.

Even college tuition and fees showed just a slight 2.2% year-over-year increase. That could still change, however. Tuition tends to be increased in the one or two months before the academic year starts, according to Ms. Rosner-Warburton.

"Major changes in the economy earlier in the year or the prior year might not even show up until that summer period," she said.

A closer look across many industries reveals other pockets of relief amid a widespread surge in prices. Men's suits are pricier, but men's pants and shorts aren't. Beef and veal prices increased by 4.1% in June compared with the year before, but the price of uncooked beef steaks declined by 0.3%. Lettuce for salad costs 11.4% more, but the price of tomatoes in the same bowl went up only 0.6%.

"It's not a single, simple story," said Jayson Lusk, a professor and head of agricultural economics at Purdue University.

'It's **not a single, simple story**,' said the head of agricultural economics at Purdue University.

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U.S. Added 528,000 Jobs in July

by Gabriel T. Rubin – WSJ – Aug. 5, 2022

Payrolls returned to pre-pandemic level; unemployment rate fell to 3.5%.

Businesses have continued to hire despite two straight quarters of economic contraction.

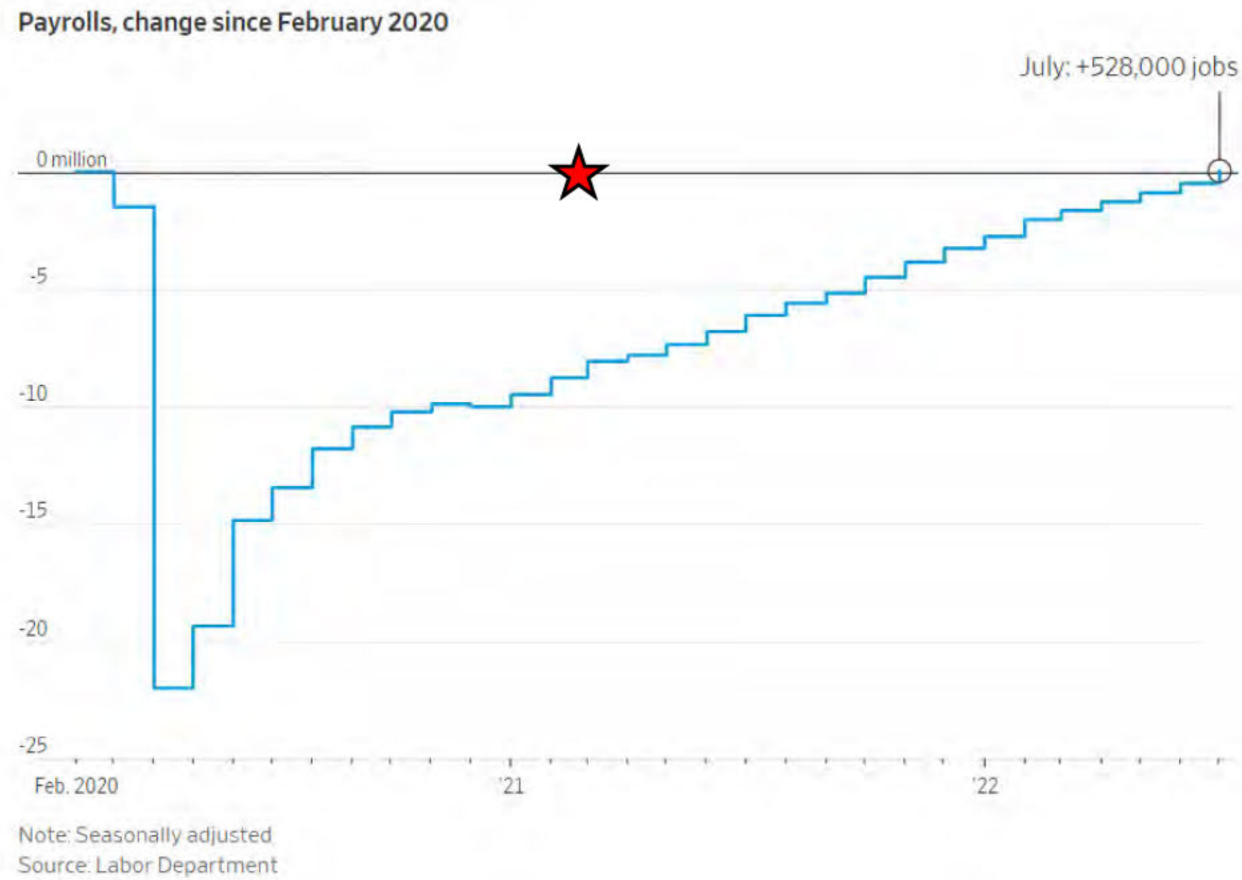
The **U.S.** economy **added** a robust **528,000 jobs in July**, recouping the number of payrolls lost in the wake of the pandemic.

The **unemployment rate also dropped to 3.5%**, a **half-century low** **also seen just before the pandemic in early 2020**, the Labor Department said Friday. The acceleration follows a first half of the year during which payrolls grew faster than during any other post-World War II period when the economy began contracting.

The **labor-force participation rate** – or the share of adults working or seeking a job – **ticked down to 62.1%** in **July** from 62.2% a month earlier. **Average hourly earnings grew 5.2%** in **July from** a **year earlier**, a slight acceleration over the prior month.

U.S. stocks dropped at the open after the report that the economy added far more jobs than expected.

Job gains were widespread last month. Employers in leisure and hospitality added jobs at a solid clip, as restaurants and bars continued to recover. Payrolls also grew in health care and professional and business services, which includes many white-collar jobs.



Industries vulnerable to the Federal Reserve's interest-rate increases also performed well in July. Construction firms, manufacturers and finance companies all added to payrolls.

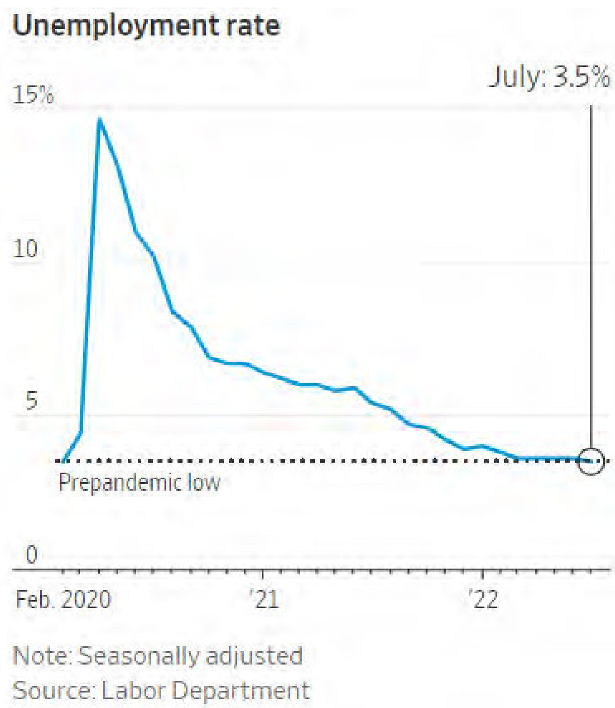
Businesses have **continued to hire despite two straight quarters of economic contraction**, cooling consumer spending and rising risks of a recession. **Overall employment** also has **nearly returned to pre-pandemic levels**. But demand for workers in some sectors is cooling as the economy transitions away from the red-hot expansion that followed the elimination of Covid-19-related restrictions on business activity.

But some companies such as Walmart, Inc. and Robinhood Markets Inc. are **cutting staff**, but **overall layoffs are slowly rising**, according to weekly unemployment claims.

"Companies used to reach for layoffs as the first option," said Greg Daco, chief economist for EY-Parthenon, a consulting firm. "Now we're seeing slower hiring as option number one, followed by targeted hiring freezes, followed by targeted layoffs, followed by broader layoffs."

U.S. job openings remained elevated but fell in June to their lowest level in nine months and fell by 600,000 from May, according to a separate report from the Labor Department released Tuesday. Total job openings remained well above the number of unemployed workers looking for a job.

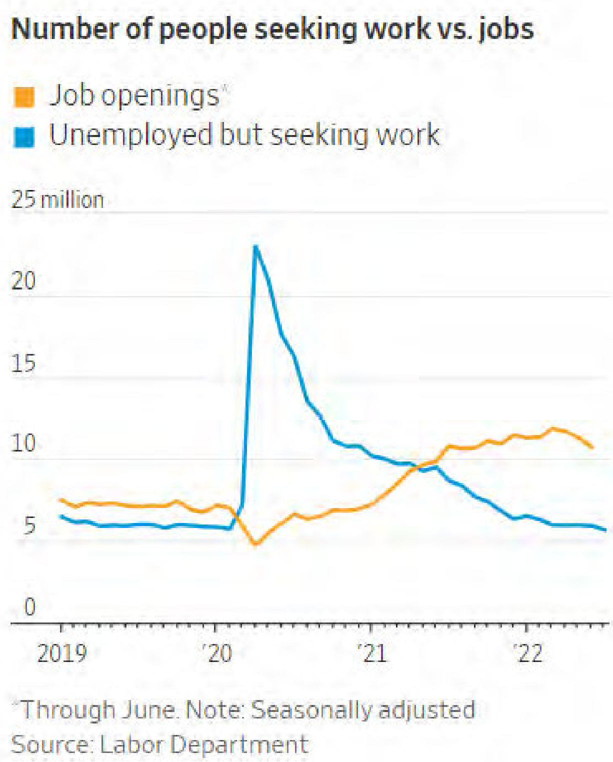
Federal Reserve officials are hopeful they can achieve a "soft landing" for the U.S. economy as they try to bring down the **highest inflation** in **four decades** without a major increase in unemployment. Fed Chairman Jerome Powell told reporters recently that the number of job openings could fall significantly without a big rise in unemployment.

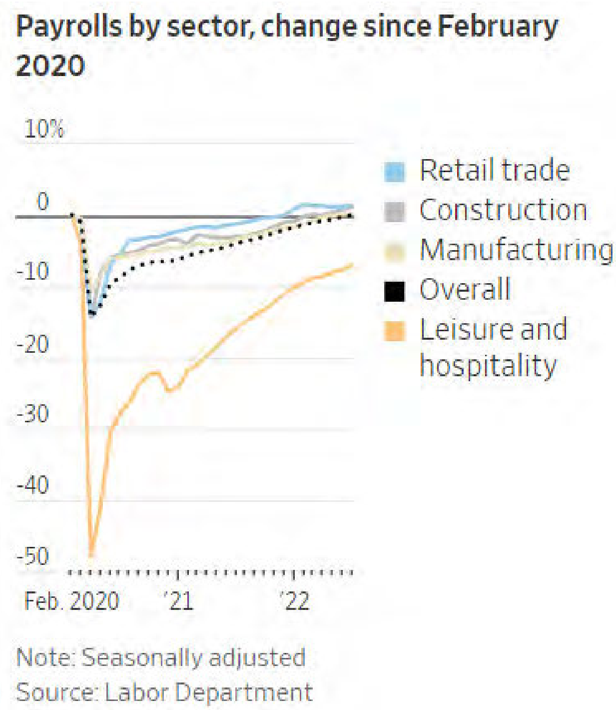


So far, average weekly layoffs have ticked up only slightly, and anecdotal evidence suggests that they are primarily affecting sectors like technology and real estate, which are more sensitive to interest-rate increases. A number of tech companies, including Microsoft Corp., Meta Platforms Inc. and Netflix Inc., in recent months have laid off employees or stalled hiring to deal with slowing growth and fallout from other macroeconomic factors.

Demand for workers is still high in sectors that haven't fully recovered from Covid-19, including leisure and hospitality, education and healthcare.

Matt Zebatto, chief executive of Life's WORC, a nonprofit that runs group homes, job training and other programs for individuals with developmental disabilities in New York City and nearby counties, said that his agency's staffing challenges are approaching crisis levels. Out of 730 positions for direct support professionals – employees who staff group homes round-the-clock – Mr. Zebatto is trying to fill more than 200.





The organization has been hamstrung by reimbursement rates from governmental healthcare programs like Medicaid that haven't kept up with prevailing wages in the labor market, hurting his ability to hire. In many areas, the rate is currently $15 an hour, and even with an expected inflation adjustment, the rate will remain under $16. Understaffing is a major issue, because of the level of care required by many group home residents. And when existing employees need to continuously work overtime shifts, it leads to more burnout and turnover.

"You can't automate helping someone put on adult diapers or helping someone into a tub," Mr. Zebatto said. "I'm grateful that someone who is working in the service industry is getting what they can get, but it makes it more difficult for us," he said of the higher wages workers can earn working elsewhere.

Despite the cooling in the labor market, some economists expect more people to look for work as inflation weighs on household budgets.

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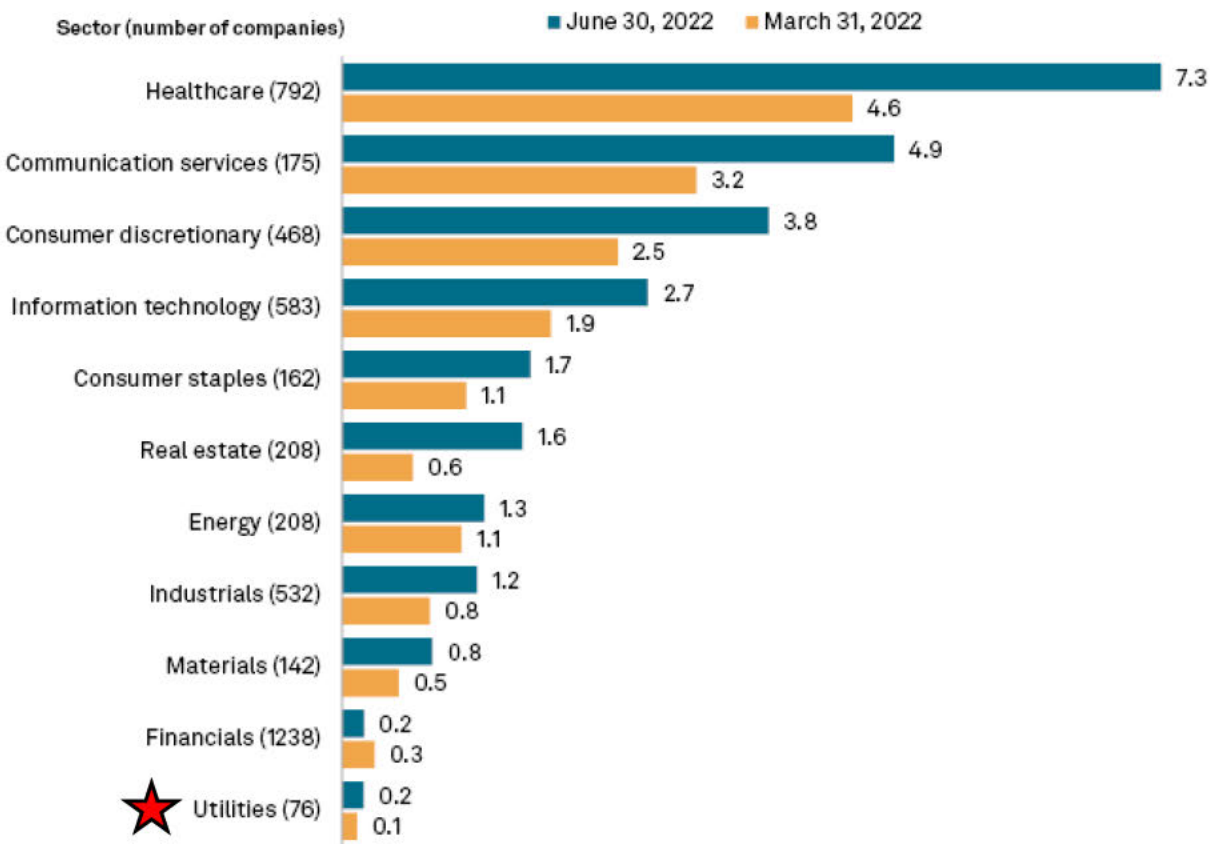
Default Risk Rises across Most US Sectors in Q2

By Anne D'Innocenzio and Alex Nierves, AP – Oregonian – Jul. 29, 2022
Data Source Sited: S&P Global Market Intelligence
[Default risk rises across most US sectors in Q2 | S&P Global Market Intelligence (spglobal.com)]

The odds of default across most U.S. business sectors rose in the second quarter.

Every sector except financials recorded a higher median market signal one-year probability of default score at the end of the second quarter compared with the end of the first quarter, according to S&P Global Market Intelligence data. The scores, which represent the **odds of default within a year**, are based primarily on the volatility of share prices for public companies in the sector and account for country- and industry-related risks.

Median market signal 1-year probability of default by US sector (%)



Data compiled July 13, 2022.
Includes publicly traded U.S. companies and investment firms that primarily trade on the Nasdaq, NYSE or NYSE American.
Probability of default scores calculated using S&P Global Market Intelligence's Market Signal probability of default model, which is based primarily on volatility of share prices, taking into account country and industry-related risks.
S&P Global Ratings does not contribute to or participate in the creation of credit scores generated by S&P Global Market Intelligence.
Industries are classified according to the Global Industry Classification Standard of S&P Global Market Intelligence.
Source: S&P Global Market Intelligence

Vulnerable Sectors

The healthcare sector had the highest one-year probability of default at 7.3% as of June 30, according to Market Intelligence data. This is up from 4.6% on March 31.

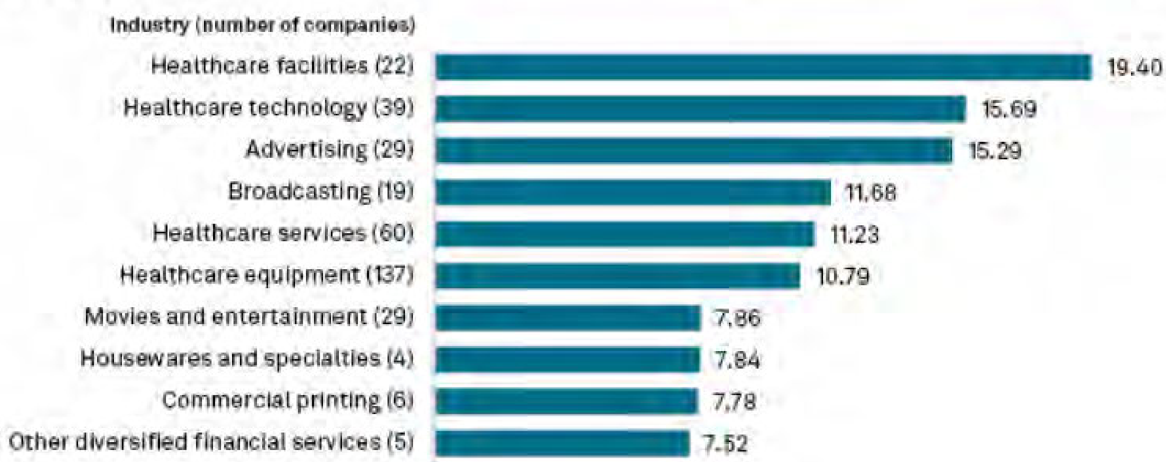
Staffing shortages, a wave of canceled elective procedures, and pandemic fears stressed the healthcare sector, which has also has one of the highest numbers of bankruptcies so far in 2022.

Communication services had the second-highest median market signal at 4.9%, up from 3.2%, according to the data. Consumer discretionary was at 3.8%, up from 2.5%. This sector, which largely includes businesses that sell goods and services viewed as nonessential, was hit hard by pandemic restrictions, COVID-19 worries and rising inflation.

Troubled Industries

Healthcare industries were in the top two with the highest probability of default scores in the second quarter, with healthcare facilities at 19.4% and healthcare technology at 15.69%, according to Market Intelligence. Advertising came in third at 15.29%.

Most vulnerable US industries by median market signal 1-year probability of default (%)



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Excludes industries with less than three companies scored as of June 30, 2022.
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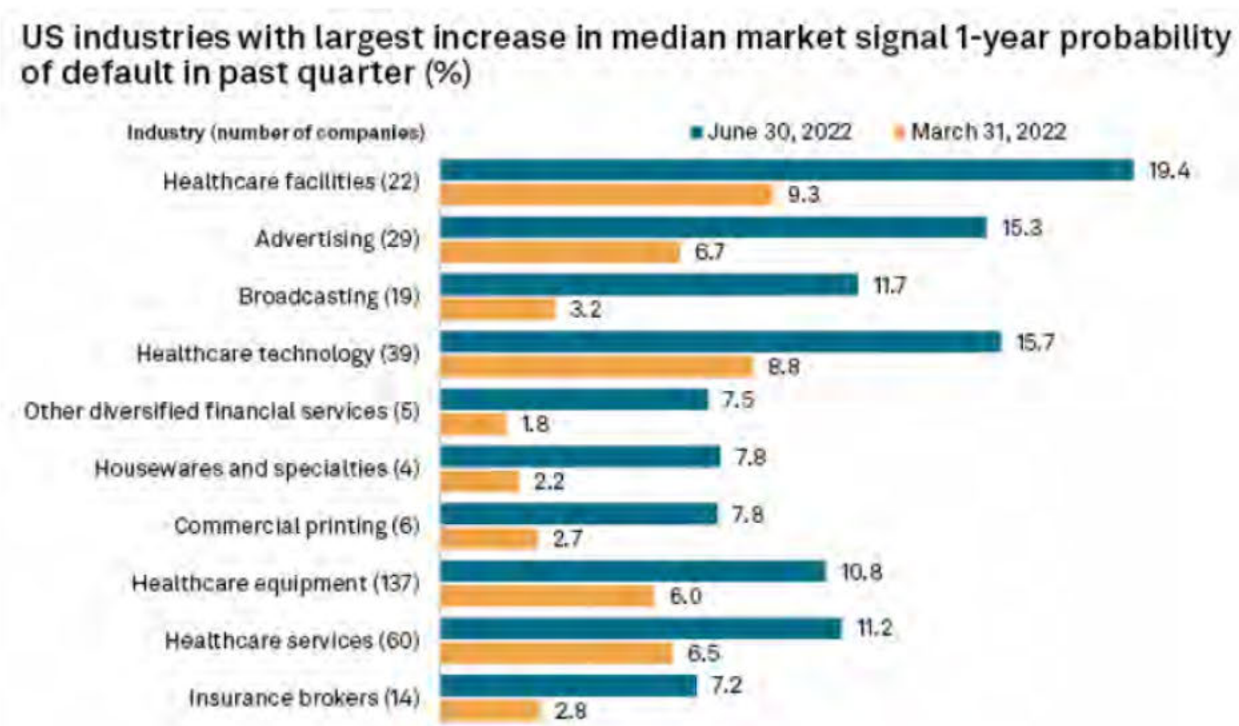
Industries are classified according to the Global Industry Classification Standard of S&P Global Market Intelligence.
Source: S&P Global Market Intelligence

Multi-line insurance, property and casualty insurance, and **gas utilities** were the **least vulnerable industries by median market signal one-year probability of default**.

Increases and Decreases

Healthcare facilities had the largest increase in probability of default at 19.4% as of June 30, up from 9.3% on March 31, according to Market Intelligence data.



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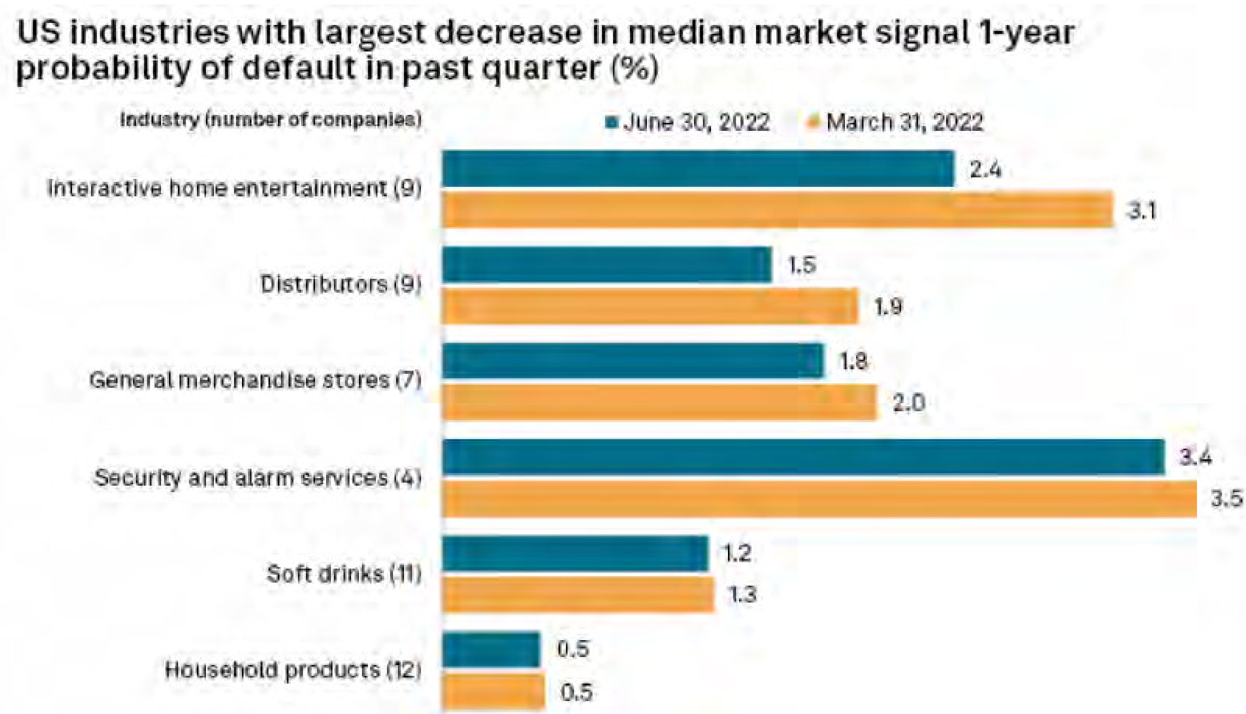
S&P Global Ratings does not contribute to or participate in the creation of credit scores generated by S&P Global Market Intelligence.
Industries are classified according to the Global Industry Classification Standard of S&P Global Market Intelligence.
Source: S&P Global Market Intelligence

Advertising had the second-largest increase at 15.3%, up from 6.7%. Broadcasting was up 11.7% from 3.2%.

Interactive home entertainment, distributors, and general merchandise stores were industries with the largest decrease in probability of default as of June 30, according to the data.



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US Energy ROE Determinations in H1'22 at All-Time Lows as Inflation Soars

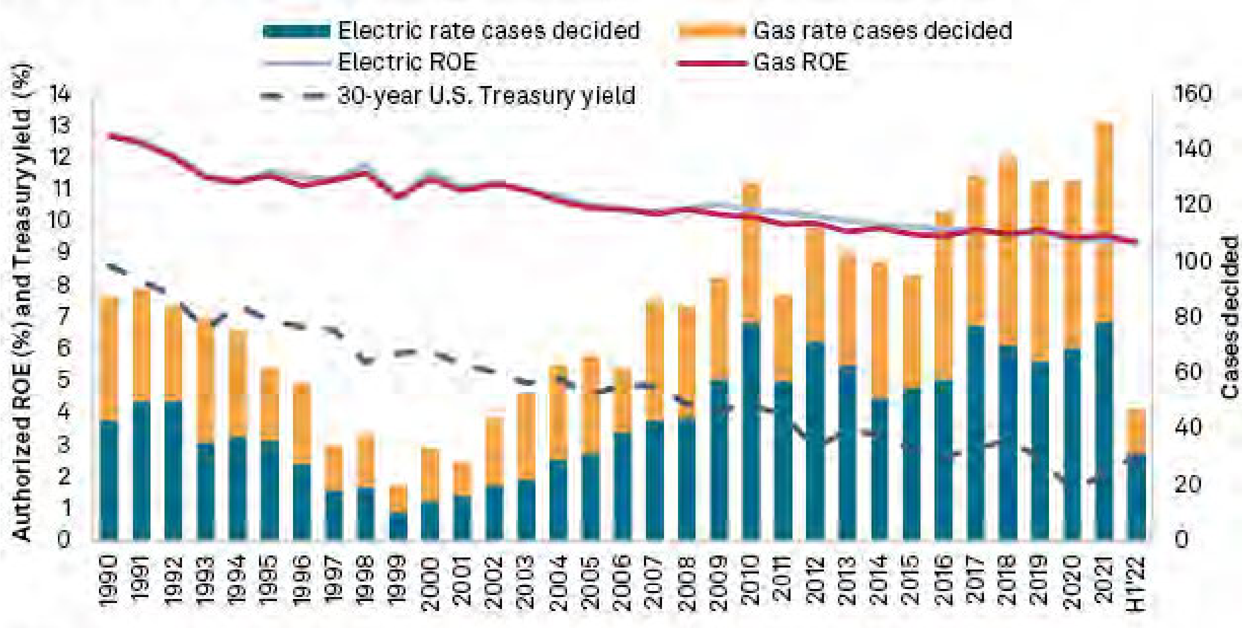
by Lisa Fontanella – S&P Global Market Intelligence – Jul 27, 2022

The **average electric** and gas authorized **returns on equity** for the **first half of 2022 remain** at **all-time lows**.

The average authorized return on equity for electric utilities was 9.39% in rate cases decided in the first half of 2022 – largely in line with the 9.38% average for full-year 2021. There were 19 electric ROE authorizations in the first half of 2022 versus 55 in full-year 2021.

The average authorized ROE for gas utilities was 9.33% in cases decided in the first half of 2022 versus 9.56% in full-year 2021. There were nine gas cases that included an ROE determination in the first half of 2022 versus 43 in full-year 2021.

Average electric and gas authorized ROEs and total number of rate cases decided



Data compiled July 22, 2022.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; U.S. Department of the Treasury

The electric data set includes several limited-issue rider cases but excluding the rider cases makes little difference in the average ROE. Historically, the annual average authorized ROEs in electric cases that involved limited-issue riders were meaningfully higher than those approved in general rate cases, driven primarily by substantial ROE premiums authorized in generation-related limited-issue rider proceedings in Virginia. However, these premiums were approved for limited durations and have since begun to expire. As a result, the gap between the average ROE in the rider cases and in general rate cases has narrowed. In the gas industry sector, there has not been much use of limited-issue rider cases, as most of the gas riders rely on ROEs approved in a previous base rate case. Excluding rider cases, the average authorized ROE for electric cases was 9.34% in the first half of 2022 versus 9.39% in full-year 2021.

In the first half of 2022, the median ROE authorized in all electric utility rate cases was 9.20% versus 9.38% in full-year 2021; for gas utilities, the metric was 9.25% in the first half of 2022 versus 9.60% in full-year 2021.

Looking at the 12 months ended June 30, the average ROE authorized in all electric utility rate cases was 9.37% and the median was 9.35%. For gas utilities in the 12 months ended June 30, the average was 9.48% and the median was 9.45%.

For a chronological listing of the major energy rate case decisions issued during 2022, as well as historical summary data going back to 1990, see RRA's latest Rate Case Decisions Quarterly Update.

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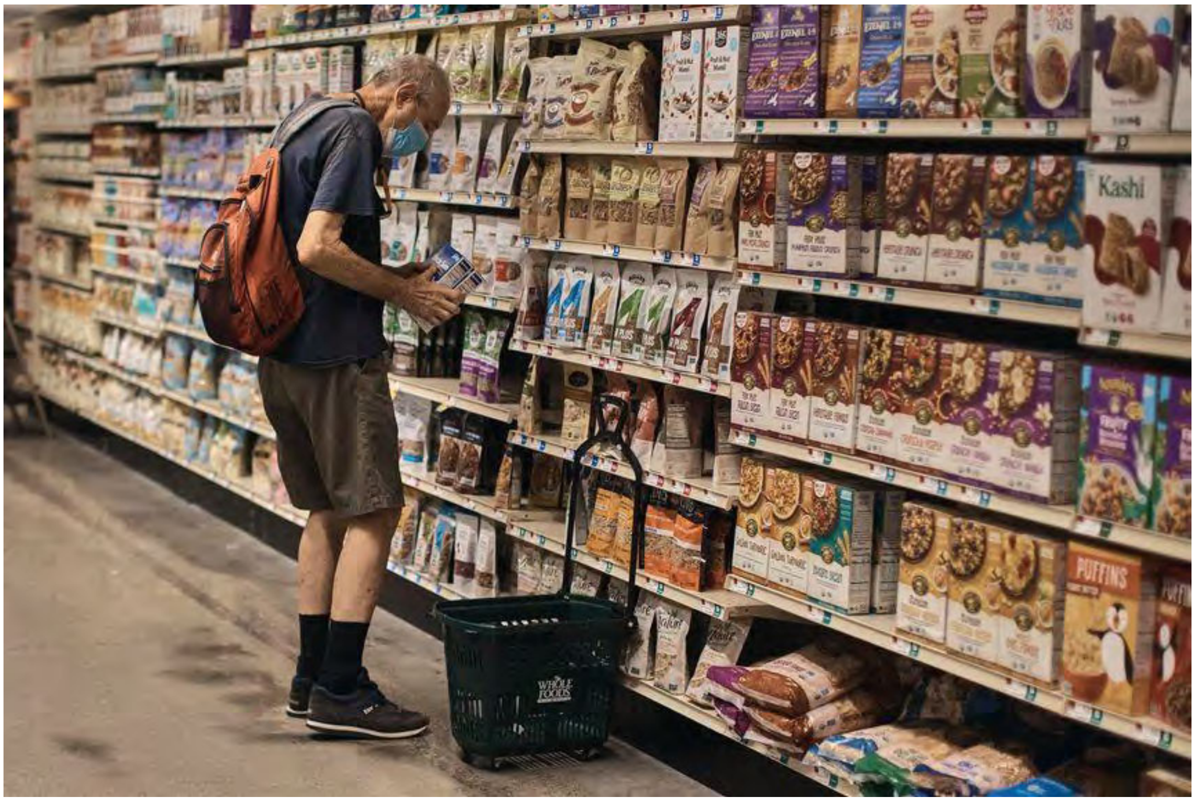
U.S. GDP Fell at 0.9% Annual Rate in Second Quarter; Recession Fears Loom Over Economy

by Harriet Torry – WSJ – Jul. 28, 2022

Economy contracted at annualized 0.9% after shrinking earlier in the year, held back by rising inflation and interest rates



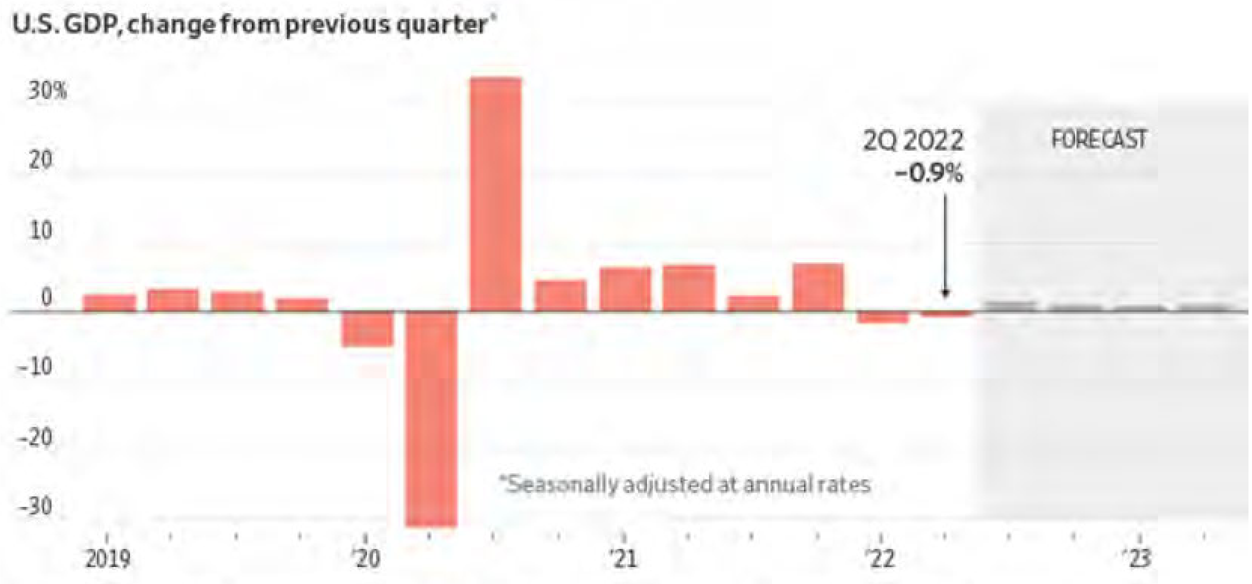
U.S. consumers face higher prices on store shelves, but have benefited from robust savings during the pandemic and a strong job market.

The **U.S. economy shrank** for a **second quarter in** a row – a **common definition** of **recession** – as the housing market buckled under rising interest rates and high inflation took steam out of business and consumer spending.

Gross domestic product, a broad measure of the goods and services produced across the economy, **fell** at an inflation and seasonally adjusted annual rate of **0.9%** in the **second quarter**, the **Commerce Department** said Thursday. That **followed** a **1.6%** pace of **contraction** in the **first three months** of **2022**.

The report indicated the economy met a commonly used definition of recession—two straight quarters of declining economic output.

The **official arbiter** of **recessions** in the **U.S.** is the **National Bureau of Economic Research**, which defines one as a significant decline in economic activity, spread across the economy for more than a few months. Its **Business Cycle Dating Committee** considers factors including employment, output, retail sales and household income, and it **usually doesn't make** a **recession determination until long after** the **fact**.



Sources: Commerce Department (actual); Wall Street Journal Economic Forecasting Survey (forecasts)

Whether or not the U.S. is in a recession now, ING economist James Knightley said that a downturn is "really only a matter of time," given pressure on American households from inflation, equity markets and "the housing downturn really gathering pace now," which he said "reinforces the feeling that it's only a matter of time before we're in a proper recession."

Analysts noted that much of the decline in the second quarter was due to a slower pace of inventory restocking.

Most economists surveyed this month by The Wall Street Journal expect the economy to grow in the third quarter and in 2022 as a whole, though lately they have lowered their estimates.

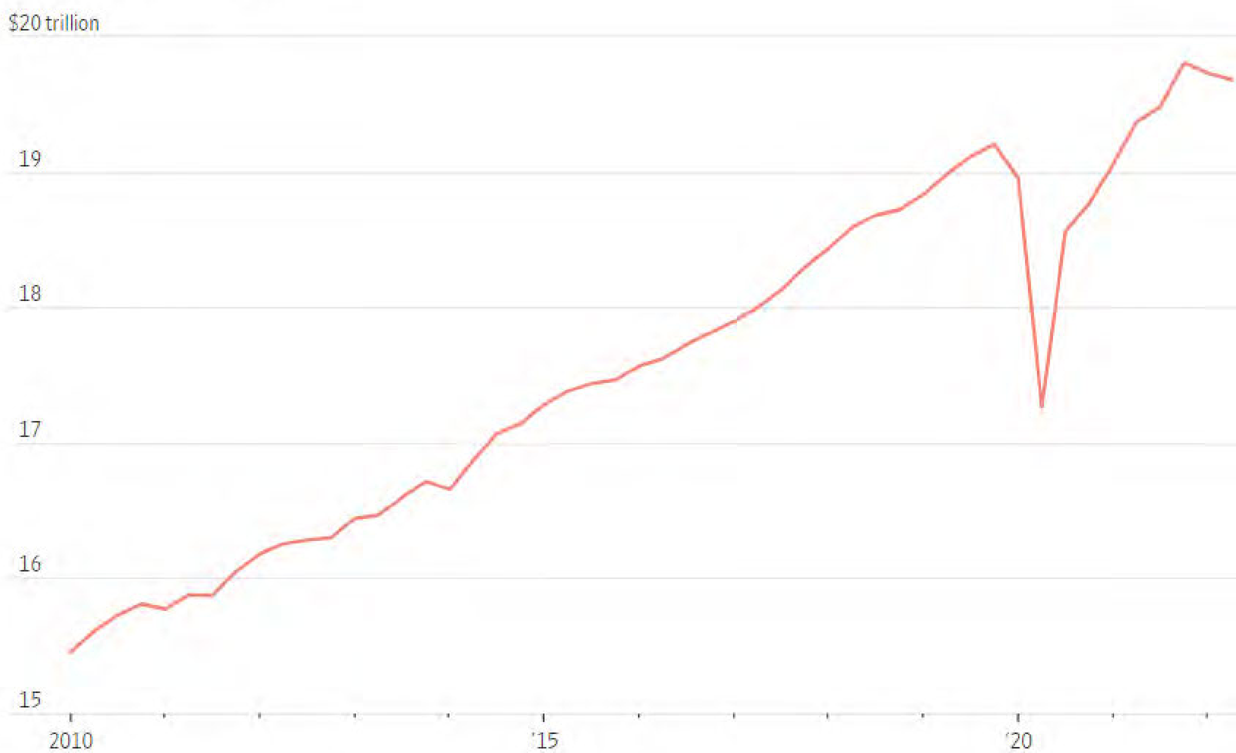
"We're seeing a sharp and necessary deceleration rather than a recession," said David Mericle, chief U.S. economist at Goldman Sachs, adding that slower growth is needed to rebalance the economy's supply and demand for goods and services, and cool wage growth and inflation. "I wouldn't say we seem to be in contractionary territory on a go-forward basis," he added.

The new figures mark a **sharp pullback from** the **final quarter** of **2021**, when **GDP rose** at a **6.9% annual rate**. That capped a year in which the economy recovered strongly from the effects of the 2020 pandemic-driven recession and posted its best annual growth since 1984, **stoked by low interest rates** and **roughly $6.4 trillion** of **government borrowing** and **spending since Covid-19** struck.

President Biden took office a year-and-a-half ago pledging to heal a nation battered by the pandemic by boosting a nascent economic recovery with massive assistance from Washington. Headed into midterm elections this fall, the latest figures have put the White House on the defensive about the state of the economy.

The GDP report underscored the **challenges** facing U.S. businesses, households and policy makers – including **high inflation**, **weakening consumer sentiment** and **supply-chain volatility**.

Quarterly U.S. GDP level*



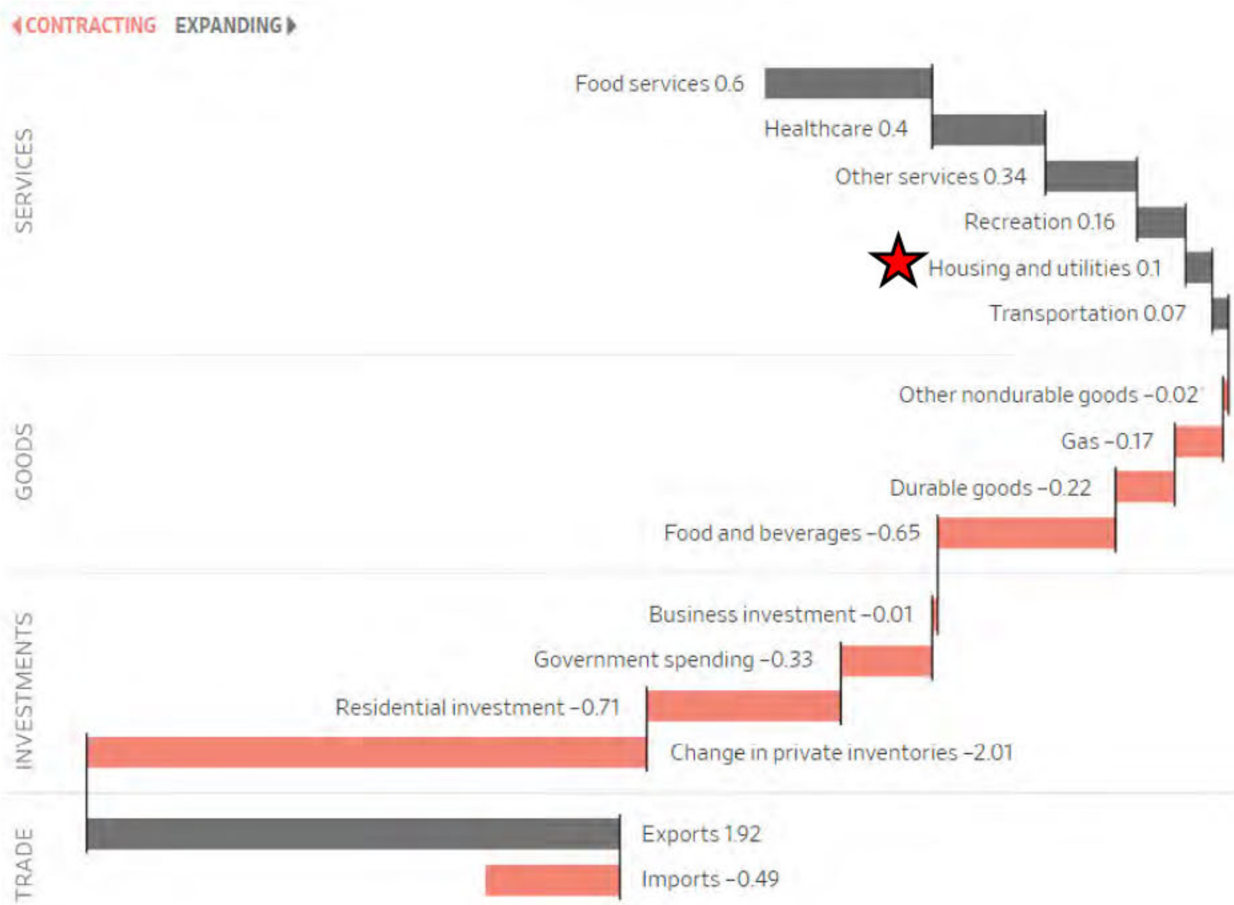
*Seasonally and inflation adjusted at annual rates
Source: Commerce Department

Consumer spending, which accounts for roughly two-thirds of total economic output, rose at a 1% annual rate in the second quarter, down from 1.8% in the first quarter. People continued to travel and shop as more people gained jobs.

Inflation hit a **fresh four-decade high** during the **second quarter**, **eroding Americans' purchasing power**. The **Fed**eral Reserve responded by **aggressively raising interest rates**, which in turn **cooled** the **housing market**, reducing brokers' commissions and **denting construction**. The **central bank raised rates Wednesday** and **indicated more increases** were **likely**.

Residential investment subtracted 0.71 percentage point from GDP. Business investment worsened slightly, with spending on structures and equipment declining.

The **U.S. economic** recovery is following an unusual **trajectory**, with **weakening output but strong job gains**. The unemployment rate, a key barometer of economic health, held steady at a low 3.6% for the past four months, and employers continued to hire at a strong pace. The Labor Department said Thursday that new applications for unemployment benefits, a proxy for layoffs, held last week near the highest level of the year, a sign that the tight labor market is loosening.



Inventories – specifically, the pace of restocking – accounted for much of the decline in the second quarter, subtracting 2.01 percentage point from GDP. A **shift** in **consumer spending away from goods** and back **toward services**, and rising prices cutting into people's buying power, left many companies with stockpiles of products they are now discounting to unload.

Walmart Inc. said on Monday that it was having to cut prices to reduce merchandise levels at its flagship chain and Sam's Club warehouse chain. Many manufacturers are also still struggling with pandemic-related supply-chain disruptions.

Business is "a little unhealthy right now" at Best Tool & Engineering Co., according to its president, Joseph Cherluck. The company, based in Clinton Township, Mich., makes tools and plastic components like welding fixtures for vehicle dashboards, and the nationwide shortage of computer chips means auto makers are pushing back orders.

"Autos are waiting for chips and we're seeing it down the supply chain," said Mr. Cherluck, adding that he is concerned about the economy slowing. The 15-employee company has frozen equipment purchases and scaled back hiring plans as a result. "I feel uncertain about the rest of the year," Mr. Cherluck said.

U.S. 10-year Treasury yield

Source: Tullett Prebon

Trade provided one bright spot in the report: **Exports rose** at a robust **18% annual rate**, as demand picked up for American-made goods and more international travelers returned to the U.S. after pandemic disruptions.

Some economists prefer to look at final sales to domestic purchasers – a subset of GDP that doesn't include the often-volatile categories of inventories and trade – to better gauge U.S. economic activity. Final sales fell at a 0.3% annualized pace in the second quarter, after rising at a 2% pace in the first.

Americans still have relatively healthy balance sheets. After the pandemic hit the U.S. economy in early 2020, increased household saving, **government stimulus checks** and **enhanced unemployment benefits** boosted household finances. The resulting "excess **savings**" – the amount **above** what they would have had there been

no pandemic – remains **elevated**. According to Moody's Analytics, excess savings totaled $2.5 trillion in May.

Some consumers are hunkering down now. Aimie Gresham of Essex, Conn., has pulled back on discretionary spending – like dining out and expensive salon visits – to pay the higher prices for basics like oil, electricity and groceries in recent months.

"Even my cat's food has gone up" by about $10 a bag over the past year, said Ms. Gresham, who works at a retirement financial firm. Her husband's car has 250,000 miles on it, but the couple decided not to replace it because of the current high prices. "In any other market we would be buying a new car right now," the 54-year-old said.

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US Supreme Court Restricts EPA's Climate Authority over Existing Power Plants
by Zack Hale and Molly Christian – S&P Global Market Intelligence – Jun. 30, 2022

The U.S. Supreme Court Building in Washington, D.C.

The **U.S. Supreme Court**'s conservative majority moved **June 30** to **constrain** the **U.S. E**nvironmental **P**rotection **A**gency's **authority** to **regulate greenhouse gas emissions from existing power plants**.

The court's conservative justices in a **6-3 opinion** found that the **Obama-era Clean Power Plan**, a **2015 rule** that never took effect, adopted an approach to curbing power plant emissions that **exceeded** the **agency's authority**.

According to the majority, the **Clean Air Act does not authorize** the **EPA** to **cap planet-warming emissions from existing power plants at** a **level that would result** in an **industrywide shift away from fossil fuels**. That **authority would need** to **be expressly given** to the **agency by Congress** pursuant to a legal standard known as the "**major questions doctrine**," the majority held in an opinion written by Chief Justice John Roberts.

In a joint dissent, the court's liberal justices argued that the decision will strip the EPA of power given by Congress to respond to "the most pressing environmental challenge of our time."

The White House was quick to condemn the court's decision.

"This is another devastating decision from the Court that aims to take our country backwards," a White House spokesman said in a statement. "Our lawyers will study the ruling carefully, and we will find ways to move forward under federal law. At the same time, Congress must also act to accelerate America's path to a clean, healthy, secure energy future."

The EPA rules

At issue are two rules the EPA issued to address greenhouse gas emissions: the Clean Power Plan issued under former President Barack Obama and the Affordable Clean Energy rule issued under former President Donald Trump.

The **Clean Power Plan** relied on an array of "outside the fence line" emission reduction measures such as coal-to-gas generation shifting and emission trading schemes, as well as "inside the fence line" efficiency upgrades for existing plants. It was projected to cut U.S. power-sector carbon emissions by 32% by 2030, relative to 2005 levels.

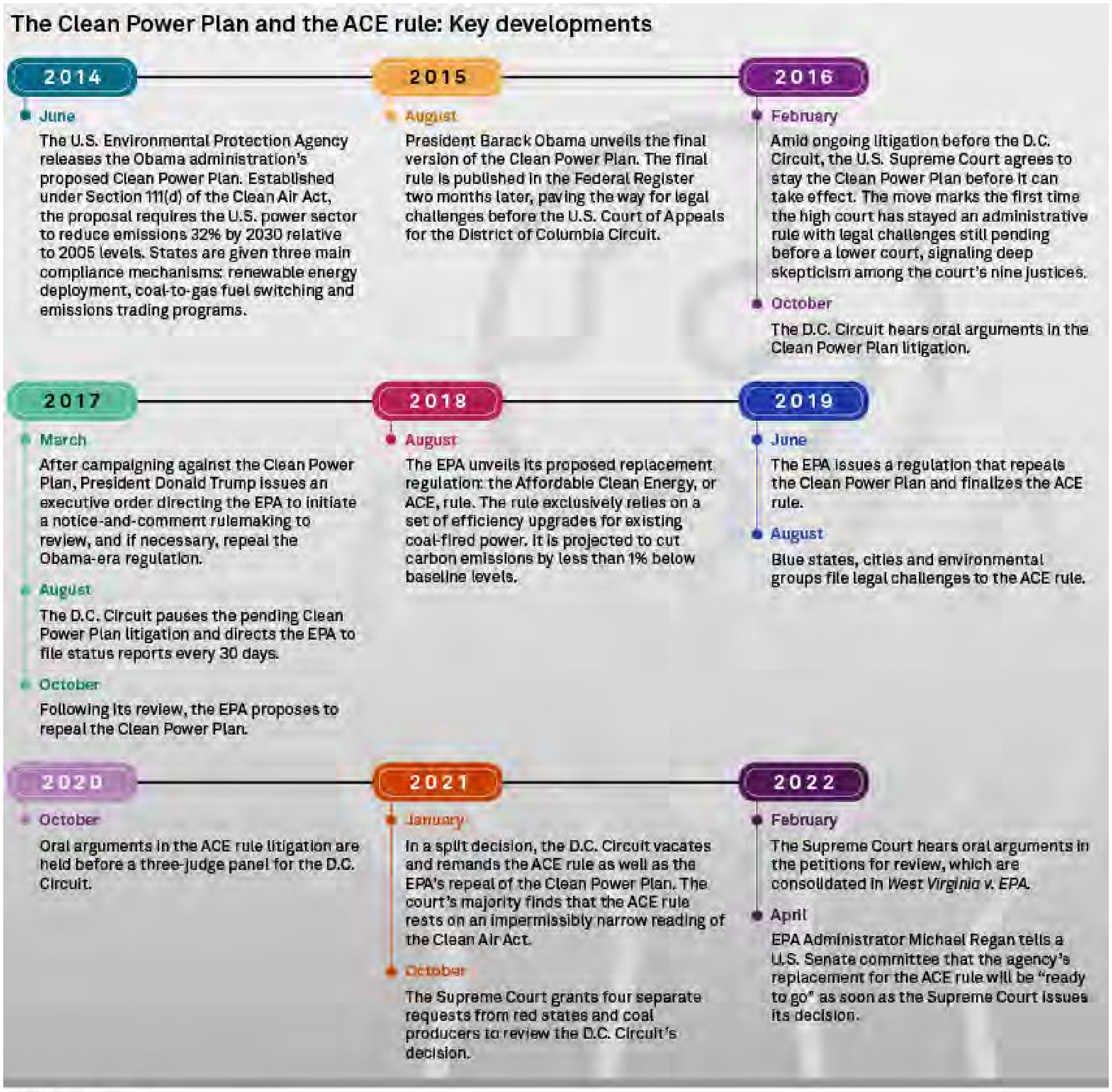
However, the Clean Power Plan was stayed by the Supreme Cour in 2016 and ultimately never took effect. Nevertheless, market forces allowed the industry to meet that target before the 2022 start date of the program.

The **Affordable Clean Energy** rule repealed and replaced the Clean Power Plan. It focused exclusively on a menu of efficiency upgrades for existing coal plants and was estimated to cut U.S. power-sector emissions by less than 1% by 2030 compared to a baseline scenario with no rule in place. But that rule also never took effect after the U.S. Court of Appeals for the District of Columbia in January 2021 vacated and remanded it.

The D.C. Circuit reasoned that it rested on an impermissibly narrow reading of Section 111(d) of the Clean Air Act. That section of the statute requires the EPA administrator to identify the "best system of emission reduction" for existing power plants.

The Trump administration said the only lawful reading of that section of the statute, which covers existing fossil fuel-fired power plants, prohibited the Clean Power Plan's system-wide approach. But the D.C. Circuit disagreed, reasoning that the Affordable Clean Energy rule ignored the electric utility industry's long-standing practice of generation shifting to comply with Clean Air Act rules.

A number of legal challenges by a coalition of Republican-led states and coal producers seeking to reinstate a rule were then consolidated for the Supreme Court's consideration.



As of June 7, 2022.
Design credit: Arleigh Andes
Source: S&P Global Commodity Insights

The Supreme Court's decision

In a 37-page majority opinion, the court's conservative majority found that the case at hand was justiciable, even though the Biden EPA is in the midst of responding to the D.C. Circuit's remand.

Plaintiffs in the case – including **Westmoreland Coal** Co. **and** The **North American Coal** Corp. – had asked the court to review whether Congress intended to give the EPA power to make decisions of vast "economic and political significance" under Section 111(d) of the Clean Air Act.

The justices concluded that the only interpretive question before the court was more narrow: whether the "best system of emission reduction" identified by the EPA in the Clean Power Plan was within the agency's authority under Section 111(d).

"**Capping carbon dioxide emissions** at a **level** that will **force** a **nationwide transition away from** the **use of coal** to **generate electricity may be**" a **sensible solution** to the **climate crisis**, the majority said. "**But** it is **not plausible** that **Congress gave EPA** the **authority** to **adopt on its own** such a **regulatory scheme** in Section 111(d). A decision of such magnitude and consequence rests with Congress itself, or an agency acting pursuant to a clear delegation from that representative body."

The **Supreme Court**, therefore, **reversed** the **D.C. Circuit's decision** to toss the Affordable Clean Energy rule and remanded it for further proceedings consistent with its opinion. Joining Roberts in the decision were Justices Samuel Alito, Clarence Thomas, Brett Kavanaugh, Neil Gorsuch and Amy Coney Barrett.

Liberal justices dissent

Justice Elena Kagan led the court's three liberal judges in an over 30-page dissent to the June 30 opinion.

"Today, the Court strips the Environmental Protection Agency of the power Congress gave it to respond to 'the most pressing environmental challenge of our time,'" Kagan wrote, referencing the court's description of climate change in its Massachusetts v. EPA ruling from 2007.

Kagan described the environmental and human toll of a warming climate, saying that "if the current rate of emissions continues, children born this year could live to see parts of the Eastern seaboard swallowed by the ocean."

The conservative majority's limits on the EPA's authority "fly in the face of the statute Congress wrote," according to Kagan, adding that Section 111(d) permitted generating-shifting by allowing the EPA to select the "best system of emission reduction" for power plants.

"The 'best system' full stop – no ifs, ands, or buts of any kind relevant here," the dissent read. "The parties do not dispute that generation shifting is indeed the 'best system' – the most effective and efficient way to reduce power plants' carbon dioxide emissions. And no other provision in the Clean Air Act suggests that Congress meant to foreclose EPA from selecting that system."

Kagan said the majority opinion rested on the claim that generation-shifting is "too new and too big a deal for Congress to have authorized" under Section 111(d), an assertion the justice said was "wrong."

Kagan added that Congress made a broad delegation under the statute so the EPA could respond appropriately to "new and big problems" and let expert agencies address significant issues when they arise.

"The majority today overrides that legislative choice," the dissent stated. "In so doing, it deprives EPA of the power needed – and the power granted – to curb the emission of greenhouse gases."

Turning to the major questions doctrine, Kagan said the current Supreme Court is "textualist only when being so suits it." Such doctrines "magically appear as get-out-of-text-free cards" if the textualist method frustrates a broader goal, Kagan said.

"Today, one of those broader goals makes itself clear: Prevent agencies from doing important work, even though that is what Congress directed," Kagan said.

Next steps for EPA

In April, EPA Administrator Michael Regan told a U.S. Senate committee that the agency will be "ready to go" with a new proposal following the high court's decision. But the EPA does not plan to issue a new greenhouse gas proposal for existing power plants until March 2023, according to the latest version of its regulatory agenda.

Clean Air Act regulations often take more than two years to be finalized and litigated to their legal conclusion, meaning a Republican administration could seek to repeal and replace a final rule yet again if Democrats fail to maintain control of the White House in 2024.

In addition to greenhouse gas regulations, the Biden EPA is also pursuing an "integrated approach" to regulating existing power plants that include rules targeting coal ash pollution and smog-forming emissions. (West Virginia v. EPA, No. 20-1.

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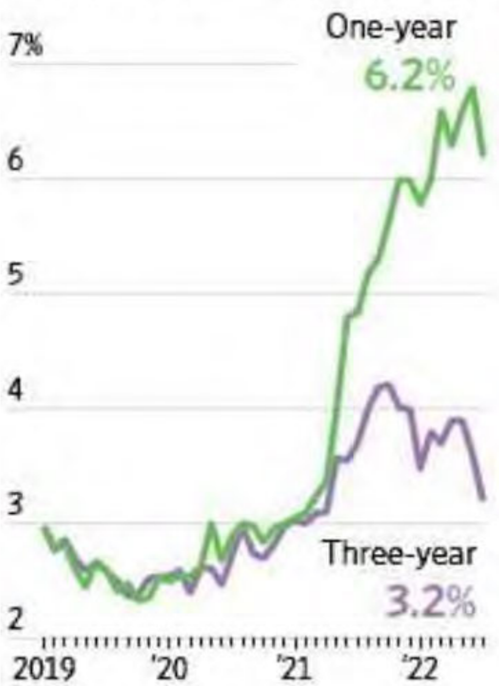
Americans Reduce Inflation Expectations

by Austen Hufford – WSJ – Aug. 9, 2022

Median expected inflation rate one year and three years ahead



Source: New York Fed Survey of Consumer Expectations

Americans are expecting less inflation in coming years, according to a recent survey by the **Federal Reserve Bank of New York**.

Respondents' **median expectation** in July was for an **annual inflation rate of 6.2% in one year**, down from the 6.8% they expected in June, the regional reserve bank said Monday. They **expected inflation** in **three years** to be **at 3.2%,** down from the 3.6% they expected in June, and inflation in **five years** to be **at 2.3%, down** from a previous 2.8%.

Economists don't see consumer expectations as a formal forecast, but pay attention to such surveys as a sign of **popular psychology** that **can influence price pressures**. **Federal Reserve officials believe expectations** of **higher inflation can be self-fulfilling**, causing people to pay higher prices and press for higher wages in anticipation of higher costs in the future, causing inflation to accelerate.

Annual inflation hit 9.1% in June, a **four-decade high**, as measured by the Labor Department's consumer-price index. Consumer prices rose 6.8% in June from a year earlier, as measured by the Commerce Department's personal-consumption expenditures price index, the Fed's preferred gauge.

The Fed seeks to keep inflation, as calculated by the PCE price index, at an average 2% over time.

Central bank policy makers are likely to welcome a decline in inflation expectations, but have signaled they are **on track to raise interest rates** in **September**, a **fifth time this year**, to mitigate price pressures.

Fed Chairman Jerome Powell has said the central bank wants to see clear and convincing evidence that price pressures are subsiding before slowing or suspending rate increases.

Economists surveyed by The Wall Street Journal in July expected inflation to ease but remain elevated at a 6.8% annual rate by December, on average, as measured by the CPI.

Jason Reed, a professor at the University at Notre Dame, said food and gasoline prices are very visible and so have a large role in how consumers view the economy. U.S. gasoline prices have fallen for more than 50 days, according to AAA. The average price of a gallon of regular gas nationally was $4.06 on Monday.

“You are starting to see consumers change their expectations,” he said.

The New York Fed survey found that consumers expected food and gasoline prices to rise more slowly in coming years. In July, they expected gasoline prices to increase 1.5% in one year, compared with 5.6% in the June poll. They expected food prices to increase 6.7%, down from their June expectations of 9.2%.

CASE: UE 399
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1809

Value Line (VL)
Electric Utilities

August 11, 2022

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 utilities, in Issue 5.

In this Issue, we present our rankings of state regulatory climates. This is always a key factor for this Industry. And with inflation heating up it's particularly important, as utilities will be looking to their regulators for rate relief in particularly challenging times.

Electric utility stocks have turned in a mixed performance so far in 2022. As is to be expected, the equities in this Industry have been less volatile than the overall market.

Ranking The Regulators

The regulatory climate for an electric utility is a key factor in the utility investment decision process. State commissions set utilities' rates, establish allowed returns on equity, approve major capital projects, and rule on proposed mergers and acquisitions. The Federal Energy Regulatory Commission (FERC) regulates interstate transmission and also rules on proposed mergers and acquisitions. While a state's regulatory commission is the major influence on the regulatory climate it's not the only factor. The governor, legislature, and courts are also relevant.

Below, we categorize each state's regulatory climate (including the District of Colombia and FERC) as Above Average, Average, and Below Average. The list excludes Nebraska, Nevada, Tennessee, Utah, and Vermont, due to a lack of major investor-owned utilities operating in those states.

• *Above Average:* Alabama, Alaska, Florida, Georgia, Idaho, Indiana, Massachusetts, Michigan, Ohio, Wisconsin, FERC.

• *Average:* California, Colorado, Delaware, Iowa, Kansas, Kentucky, Louisiana, Maine, Minnesota, Mississippi, Missouri, New Hampshire, New Jersey, North Carolina, North Dakota, Oklahoma, Oregon, Pennsylvania, Rhode Island, South Carolina, South Dakota, Texas, Virginia, Wyoming.

• *Below Average:* Arizona, Arkansas, Connecticut, District of Columbia, Hawaii, Illinois, Maryland, Montana, New Mexico, New York, Washington, West Virginia.

Arizona is a fairly recent regulatory climate downgrade due to the very poor rate case order *Pinnacle West* received from regulators last November. In Hawaii, a new performance-based rate-making plan for *Hawaii Electric Industries* appears initially constructive. In addition to performance incentives, the plan includes mechanisms that provide revenue annually based on inflation and capital spending of certain types. An upgrade to our rating of the state's regulatory climate may be warranted after monitoring the situation for a few quarters. The main regulatory commission in New Mexico remains a roadblock to that state's regulatory climate being included in our Average grouping. The New Mexico governor's office seems ready to act to rectify the situation, as it looks to streamline the agency's commissioner membership from five to three in 2023, and appoint new members that will likely be more open to the state's and its utilities' renewable energy push.

INDUSTRY TIMELINESS: 63 (of 96)

Conclusion

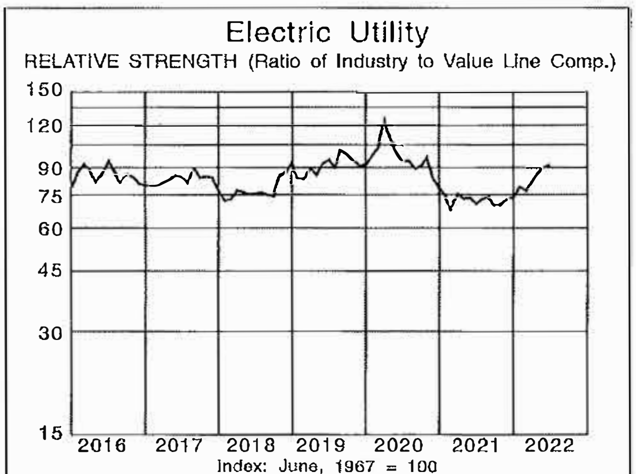
On balance, stocks in the Electric Utility Industry have fallen in price marginally (-3%) in 2022. Relative performance for the group as a whole has been very good compared to the broader market averages. Recession fears weighing on equities in general, and this group's defensive fundamentals during economic downturns, have kept it mostly insulated from the market decline.

Interest rates have climbed lately, with expectations that the Federal Reserve will keep its foot on the brakes to dampen inflation. The yield on the 10-year U.S. Treasury note reached levels that haven't been seen in more than a decade. So far, this hasn't seemed to hurt utility stocks, most likely because the market has anticipated rising rates.

There haven't been a lot of utility equities based in the Western region of the U.S. that have bucked the overall market's decline with a year-to-date gain, but *Sempra Energy* (+12%) is one. Investors have focused on the company's presence in liquefied natural gas exporting, along with its better-than-average prospects, stemming from strong growth in its Texas territory and an expanding rate base in southern California. *Xcel Energy* (+3%) is a utility that has had a history of growing its bottom line well in excess of its peer group. And *PNM Resources* (+4%) has exposure to good growth in Texas and is buoyed by a take-out offer from Northeast utility AVANGRID, Inc. The deal will most likely require an affirmative decision from the New Mexico Supreme Court in order to go through, although upcoming changes at that state's regulatory commission may also be supportive of the merger.

The average dividend yield of electric utility stocks is 3.5%, 130 basis points above the median of all dividend-paying issues covered in *The Value Line Investment Survey*. There is a wide variance in the 18-month prospects and longer-term total return potential in this Industry. Company fundamentals are quite different, largely based on the health of the local economies they serve and the regulatory climate they face. For detailed analysis of Western-based issues, we encourage subscribers to peruse the following pages.

Anthony J. Glennon



INDUSTRY TIMELINESS: 65 (of 96)

All major electric utilities located in the central region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 11.

How do we determine which one-time items are nonrecurring and which aren't? We discuss this below.

Every company in the Electric Utility Industry has reported first-quarter results. There were some similarities among what the companies stated.

Electric utility stocks, as a group, have fared far better than the broader market averages of late. This industry is living up to its reputation as a defensive haven.

What Is Nonrecurring And What Isn't

Electric utilities often show two sets of earnings: those presented on a GAAP basis and "adjusted" or "operating" earnings. Subscribers might ask how we determine whether to include or exclude certain items that management excludes from its non-GAAP earnings. Sometimes, the figures shown in the pages of *The Value Line Investment Survey* are neither the GAAP nor the adjusted number.

Gains or losses on discontinued operations are always excluded from our earnings presentation. Otherwise, whether we include or exclude something depends on the nature and magnitude of the item. For instance, several companies record mark-to-market accounting gains or losses every quarter. *American Electric Power*, *DTE Energy*, and *Fortis* are among the companies in this Industry that book these items. Management normally excludes these from its definition of operating earnings. Nevertheless, we include these—despite the fact that this skews quarterly and annual earnings comparisons—because we won't call something "nonrecurring" when it literally isn't. Other items that are included in our presentation are unrealized gains or losses on a company's decommissioning trusts for nonregulated nuclear assets; refunds of previously collected revenues; charges associated with harsh weather events such as hurricanes; and expenses associated with any kind of headcount reduction. Among the items that we typically exclude are writedowns of power plants or goodwill; gains or losses on the sale of nonutility subsidiaries; and fines. Yet even these will be included in our presentation if they are not large enough to be deemed material by the analyst.

What Happened In The First Quarter

By the second week of May, every company in the Electric Utility Industry had reported first-quarter results. In contrast to the reported decline in GDP in the first quarter, many utilities were optimistic about the economic health of their service territories. *American Electric Power*, *Entergy*, *OGE Energy*, and *WEC Energy Group* made positive comments about the state of their economies. *Entergy* saw a 6.5% increase in kilowatt-hour sales to industrial customers, which is significant because these customers are not affected by weather patterns nearly as much as residential or commercial customers.

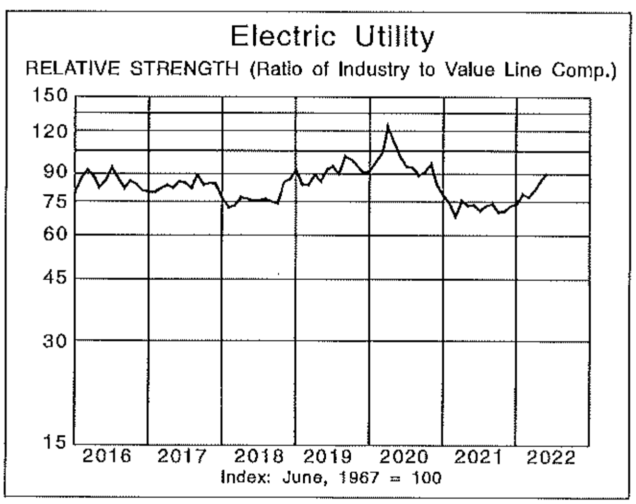
Utilities are also disclosing their plans for retiring coal-fired plants and replacing them with renewable capacity. *CMS Energy* says its utility subsidiary will be out of coal by 2025, earlier than most companies. However, obtaining solar panels has been problematic due to the effects of inflation, supply-chain disruptions, and (possibly) increased tariffs on panels imported from four countries in Southeast Asia. This might well prompt some companies to delay their expected additions of solar capacity. Some might turn to wind instead.

So far, electric companies have done an able job of dealing with the effects of inflation. They have cut discretionary expenses and reduced the employee headcount. Some costs are harder to control, such as insurance and property taxes. Utilities may seek recovery of higher costs through a rate increase, but there is no guarantee that this will be fruitful. Regulatory commissions are cognizant of the effects of inflation in power prices on electric customers, too.

Conclusion

On balance, stocks in the Electric Utility Industry have risen in price just slightly in 2022. This is in contrast to the action of the broader market averages, which plummeted in recent weeks before making a partial recovery. Utility equities are known for their defensive characteristics. The average Safety rank of stocks in the Electric Utility Industry is 2 (Above Average), and most of these issues have high scores for Price Stability. The generous dividend yields of utility issues appeal to income-oriented investors. The industry's average dividend yield is 3.2%, which is more than one percentage point above all dividend-paying stocks under our coverage. However, intermediate- and long-term investors should note that the equities in this Industry lack appeal for the 18-month span or the 3- to 5-year period. In fact, the recent quotations for some utility stocks are within their 2025-2027 Target Price Range.

Paul E. Debbas, CFA



All major electric utilities located in the eastern region of the United States are reviewed in this Issue; western electrics, in Issue 11; and the remaining utilities, in Issue 5.

Some utilities in this Issue are involved in pending deals. We discuss transactions in the Electric Utility Industry.

For companies involved in solar energy, there are concerns about inflation, possible tariff increases, and supply-chain delays.

The price of utility stocks, as a group, is down slightly so far in 2022. Even so, this Industry has outperformed the broader market averages this year.

Mergers, Acquisitions, And Other Deals

Mergers, acquisitions, spinoffs, and asset sales are common in the Electric Utility Industry. Utilities want to grow, accept an attractive offer, make strategic improvements, or raise funds for capital spending, debt reduction, or some other purpose. A few utilities reviewed in Issue 1 are involved in pending deals. However, completing transactions in this industry doesn't always occur due to the numerous regulatory approvals needed.

AVANGRID is involved in a utility combination as the acquiring company. It has agreed to buy PNM Resources, the parent of utilities in New Mexico and Texas, for $4.3 billion in cash. The companies received most of the regulatory approvals needed to complete the deal, but "most" isn't good enough. The New Mexico commission rejected the proposal, so the companies appealed the order to the state Supreme Court. *PPL Corporation* received all of the regulatory approvals needed to buy Narragansett Electric, an electric and gas utility in Rhode Island, but even this might not be sufficient to complete the purchase. The Rhode Island attorney general is trying to stop or at least amend the agreement. These two deals illustrate the difficulties electric companies often face when attempting mergers or acquisitions.

There are a few more examples of asset purchases, sales, or spinoffs in the Electric Utility Industry. *Dominion Energy* has agreed to sell its smallest utility subsidiary, a gas company in West Virginia. *Public Service Enterprise Group* completed the sale of its nonnuclear generating assets in the past several months. *Duke Energy* and *FirstEnergy* have agreed to sell a 19.9% stake in a utility subsidiary. Such a move enables a company to raise cash while still retaining operational and financial control of a utility subsidiary. *Eversource* bought a gas utility in October of 2020 and has a small water-utility acquisition pending. Finally, in early February, *Exelon* spun off its nonutility operations into a separate company.

Worries For Solar Power

Many companies in the Electric Utility Industry have built or announced solar projects in recent years. In some cases, this is done to help meet a state's renewable-energy requirements. (Wind power plays a part in this, too.) In others, this is done to meet demand from large customers. Some of these projects are constructed and owned by utilities, others by nonutility subsidiaries.

INDUSTRY TIMELINESS: 85 (of 96)

NextEra Energy is a major player in renewable energy in the United States. However, the company is worried about inflation, additional tariffs, and supply-chain problems involving solar panels. The U.S. Department of Commerce is investigating the importation of solar panels from four countries in Southeast Asia (Malaysia, Vietnam, Thailand, and Cambodia), with the possibility of imposing additional tariffs. Even if this does not come to pass, inflation and supply-chain delays are causes for concern. This might well push some planned projects from 2022 to 2023. Among companies reviewed in this week's Issue, *AVANGRID* and *Consolidated Edison* also have nonutility subsidiaries that construct and own renewable-energy projects.

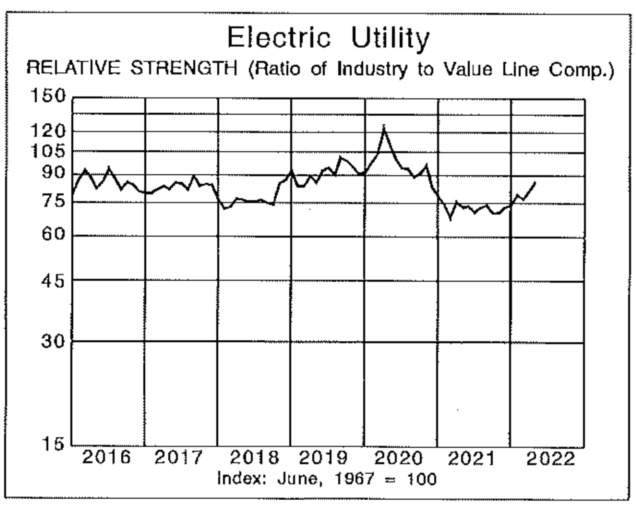
Conclusion

There has been a wide disparity in the performance of equities in the Electric Utility Industry so far this year. Even in a bad year for the overall market, some issues have advanced solidly in price. Overall, the group has retreated slightly, but has fared better than the broader market averages. *NextEra Energy* and *AVANGRID* have seen their prices hurt by the aforementioned problems with solar panels.

Interest rates are rising, but since the market anticipated this, higher rates do not appear to be a major problem for the stocks in this group, so far. However, the possibility of a recession has risen. Nevertheless, what is important for these stocks isn't so much the national economy, but the economy in the company's service area. As this report went to press, many utilities had not yet reported first-quarter results. Among those that had, *NextEra Energy* and *Southern Company* stated that the economy of their service territories was still solid. Whether this will change in the coming months remains to be seen.

The dividend yield of the Electric Utility Industry is 3.4%, which is well above the median of all dividend-paying stocks under our coverage. The group is more attractive for the dividend yield than for 18-month or 3- to 5-year prospects.

Paul E. Debbas, CFA



ALLETE NYSE-ALE

RECENT PRICE 61.97 | P/E RATIO 16.7 (Trailing: 17.8; Median: 19.0) | RELATIVE P/E RATIO 1.00 | DIV'D YLD 4.3% | VALUE LINE

TIMELINESS 4 Raised 2/25/22
SAFETY 2 New 10/1/04
TECHNICAL 3 Raised 6/10/22
BETA .90 (1.00 = Market)

18-Month Target Price Range

Low-High Midpoint (% to Mid)
$52-$86 $69 (10%)

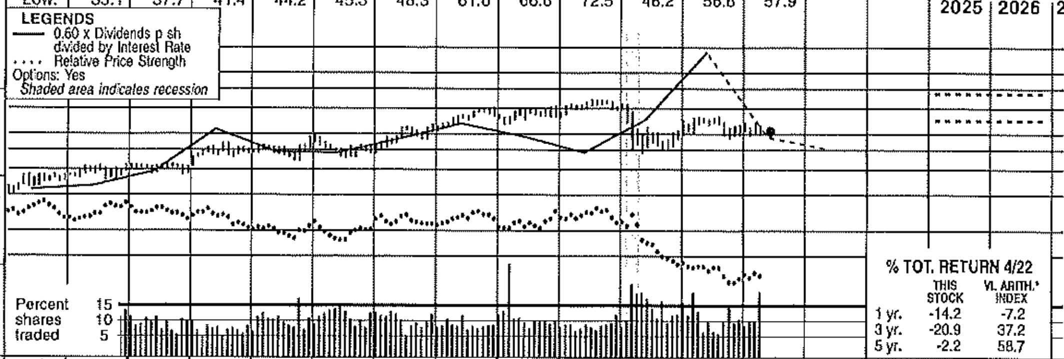
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+55%)	14%
Low	70	(+15%)	7%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	111	151	139
to Sell	111	109	131
Hld's(000)	37923	37557	39713

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	42.5	42.7	54.1	58.0	59.7	66.9	81.2	82.8	88.6	84.7	73.1	68.6
Low:	35.1	37.7	41.4	44.2	45.3	48.3	61.6	66.6	72.5	48.2	56.8	57.9



% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-14.2	-7.2
3 yr.	-20.9	37.2
5 yr.	-2.2	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
25.23	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	*26.30*	*27.15*	Revenues per sh	*29.50*
4.14	4.42	4.23	3.57	4.35	4.91	5.01	5.35	5.68	6.79	7.08	6.59	7.37	7.24	7.52	7.54	*7.95*	*8.45*	"Cash Flow" per sh	*9.75*
2.77	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	*3.70*	*3.95*	Earnings per sh A	*4.75*
1.45	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*	*2.70*	Div'd Decl'd per sh B ■ †	*3.00*
3.37	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	*3.70*	*5.95*	Cap'l Spending per sh	*7.25*
21.90	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	*47.45*	*48.90*	Book Value per sh C	*54.00*
30.40	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	*57.00*	*58.00*	Common Shs Outst'g D	*61.00*
16.5	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	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.89	.79	.84	1.07	1.02	.92	1.01	1.05	.91	.76	.98	1.16	1.20	1.32	.94	1.10	*Value Line*		Relative P/E Ratio	*.95*
3.2%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $1947.5 mill. Due in 5 Yrs $842.2 mill.
LT Debt $1669.4 mill. LT Interest $65.9 mill.
(LT interest earned: 2.7x)

Leases, Uncapitalized Annual rentals $5.1 mill.

Pension Assets-12/21 $745.7 mill.
Oblig $911.7 mill.

Pfd Stock None

Common Stock 53,308,809 shs.

MARKET CAP: $3.3 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
961.2	1018.4	1136.8	1486.4	1339.7	1419.3	1498.6	1240.5	1169.1	1419.2	*1500*	*1575*	Revenues ($mill)	*1800*
97.1	104.7	124.8	163.4	155.3	159.2	174.1	172.4	174.2	169.2	*205*	*230*	Net Profit ($mill)	*290*
28.1%	21.5%	22.6%	19.4%	11.3%	14.8%	--	--	NMF	NMF	*NMF*	*NMF*	Income Tax Rate	*NMF*
5.3%	4.4%	6.3%	2.0%	1.4%	.8%	.7%	1.3%	1.1%	1.5%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
43.7%	44.6%	44.2%	46.3%	42.0%	41.0%	39.9%	38.6%	41.0%	42.2%	*39.5%*	*39.5%*	Long-Term Debt Ratio	*40.5%*
56.3%	55.4%	55.8%	53.7%	58.0%	59.0%	60.1%	61.4%	59.0%	57.8%	*60.5%*	*60.5%*	Common Equity Ratio	*59.5%*
2134.6	2425.9	2882.2	3388.9	3263.4	3507.4	3584.3	3632.8	3887.8	4176.3	*4465*	*4700*	Total Capital ($mill)	*5550*
2347.6	2576.5	3286.4	3669.1	3741.2	3822.4	3904.4	4377.0	4840.8	5100.2	*5215*	*5300*	Net Plant ($mill)	*5675*
5.6%	5.3%	5.2%	5.8%	5.8%	5.5%	5.8%	5.6%	5.3%	4.8%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	8.1%	7.7%	7.6%	7.0%	*7.5%*	*8.0%*	Return on Shr. Equity	*9.0%*
8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	8.1%	7.7%	7.6%	7.0%	*7.5%*	*8.0%*	Return on Com Equity E	*9.0%*
2.3%	2.2%	2.5%	3.6%	2.8%	2.4%	2.7%	2.3%	2.0%	1.5%	*2.5%*	*2.5%*	Retained to Com Eq	*3.5%*
71%	72%	67%	60%	66%	68%	66%	70%	74%	78%	*69%*	*68%*	All Div'ds to Net Prof	*63%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-1.5	-12.0	+11.5
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) F	1573	1588	1557
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	277	230	219

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	--	-2.5%	3.0%
"Cash Flow"	5.5%	2.5%	4.5%
Earnings	4.0%	1.0%	6.0%
Dividends	3.5%	4.0%	3.5%
Book Value	5.0%	3.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2019	357.2	290.4	288.3	304.6	1240.5
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	*351.5*	*375*	*390*	*1500*
2023	*400*	*370*	*395*	*410*	*1575*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2019	1.18	.64	.60	.92	3.33
2020	1.28	.39	.78	.90	3.35
2021	.99	.53	.53	1.18	3.23
2022	1.24	*.61*	*.80*	*1.05*	*3.70*
2023	*1.30*	*.65*	*.90*	*1.10*	*3.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.56	.56	.56	.56	2.24
2019	.5875	.5875	.5875	.5875	2.35
2020	.6175	.6175	.6175	.6175	2.47
2021	.63	.63	.63	.63	2.52
2022	.65	.65			

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. '21 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's Minnesota Power subsidiary is awaiting an order on its general rate case. In recent years, the utility has been underearning its allowed return on equity. So, Minnesota Power filed for a $108 million (18%) rate increase, based on a 10.25% ROE and a 53.8% common-equity ratio. The company also asked for a regulatory mechanism to adjust for fluctuations in industrial kilowatt-hour sales. (One of the utility's taconite customers idled one of its facilities in May, and this probably won't be back up until the fall.) Interim tariffs were boosted by $87 million at the start of 2022, with a final order expected late in the year.

The company's utility in Wisconsin filed a rate case. Superior Water, Light and Power requested a hike of $3.3 million (2.7%), based on a 10.4% ROE and a 55% common-equity ratio. New tariffs will probably take effect at the start of 2023.

We expect a significant earnings increase this year. Rate relief at Minnesota Power should be the key factor. We also figure that wind conditions for ALLETE Clean Energy (ACE) will be better. Our estimate of $3.70 a share, which we raised by a nickel because the first-quarter tally was slightly above our estimate, is within ALLETE's targeted range of $3.60-$3.90.

The company acquired a solar-power developer in April. ACE has a significant position in wind power, but not solar power. ALLETE paid $159 million in cash. It raised $224 million through the sale of 3.7 million common shares. The purchase will probably have little effect on earnings in 2022 (transaction costs amounted to $0.03 a share in the first quarter), but should be accretive in 2023, despite the current inflation and supply-chain problems for solar panels. Accordingly, we raised our estimate by $0.05 a share, to $3.95. ALLETE's goal for annual earnings growth is 5%-7%.

This stock is untimely, but offers an attractive dividend yield. The yield is almost one percentage point above the utility average. Total return prospects over the next 18 months are unappealing, however. Total return potential to 2025-2027 is not especially high, but is superior to that of most utility issues.

Paul E. Debbas, CFA *June 10, 2022*

(A) Diluted EPS. Excl. nonrec. gains (loss): '15, (46¢); '17, 25¢; '19, 26¢; loss on disc. ops.: '06, 2¢. '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 '21: $9.62/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	40
Earnings Predictability	90

ALLIANT ENERGY NDQ-LNT

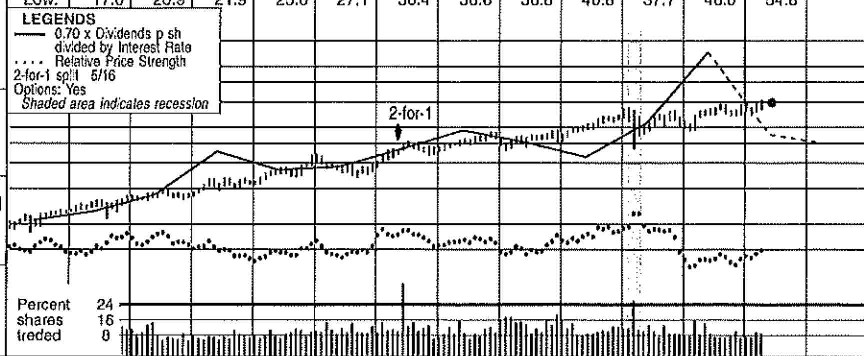
RECENT PRICE 63.78 | P/E RATIO 22.8 (Trailing: 23.5 Median: 20.0) | RELATIVE P/E RATIO 1.37 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 3 Raised 10/29/21
SAFETY 2 Raised 9/28/07
TECHNICAL 3 Lowered 6/10/22
BETA .80 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	22.2	23.8	27.1	34.9	35.4	41.0	45.6	46.6	55.4	60.3	62.3
Low:	17.0	20.9	21.9	25.0	27.1	30.4	36.6	36.8	40.6	37.7	46.0

High 65.4, Low 54.8 (2022)

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$55-$84 $70 (10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+10%)	5%
Low	50	(-20%)	-2%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	237	290	265
to Sell	232	244	259
Hld's(000)	194869	195770	195423

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.9	-7.2
3 yr.	33.7	37.2
5 yr.	71.0	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
14.46	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	*16.35*	*16.90*	Revenues per sh	*18.50*
2.16	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	*5.50*	*5.75*	"Cash Flow" per sh	*6.75*
1.03	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	*2.80*	*2.95*	Earnings per sh A	*3.50*
.58	.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*	Div'd Decl'd per sh B ■ †	*2.15*
1.71	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	*5.90*	*5.90*	Cap'l Spending per sh	*6.25*
11.42	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	*25.05*	*26.25*	Book Value per sh C	*30.25*
232.25	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	*251.00*	*251.50*	Common Shs Outst'g D	*253.00*
16.8	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	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.91	.80	.81	.93	.80	.91	.92	.86	.87	.91	1.17	1.04	1.03	1.13	1.09	1.13	*Value Line*		Relative P/E Ratio	*1.00*
3.3%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $7992 mill. **Due in 5 Yrs** $2126 mill.
LT Debt $7383 mill. **LT Interest** $272 mill.
(LT interest earned: 3.3x)

Leases, Uncapitalized Annual rentals $2 mill.

Pension Assets-12/21 $1011 mill. **Oblig** $1251 mill.

Pfd Stock None

Common Stock 250,813,728 shs.

MARKET CAP: $16 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
3094.5	3276.8	3350.3	3253.6	3320.0	3382.2	3534.5	3647.7	3416.0	3669.0	*4100*	*4250*	Revenues ($mill)	*4700*
337.8	382.1	395.7	390.9	384.0	466.1	522.3	567.4	624.0	674.0	*700*	*745*	Net Profit ($mill)	*885*
21.5%	12.4%	10.1%	15.3%	13.4%	12.5%	8.4%	10.8%	10.8%	NMF	*4.0%*	*4.0%*	Income Tax Rate	*4.0%*
6.5%	8.1%	8.8%	9.4%	16.3%	10.7%	14.5%	16.3%	8.8%	3.7%	*4.0%*	*5.0%*	AFUDC % to Net Profit	*6.0%*
48.4%	46.1%	49.7%	47.3%	51.5%	47.8%	52.3%	50.6%	53.5%	52.9%	*54.5%*	*54.0%*	Long-Term Debt Ratio	*55.0%*
48.4%	50.8%	47.5%	50.0%	46.1%	49.8%	45.7%	47.6%	44.9%	47.1%	*45.5%*	*46.0%*	Common Equity Ratio	*45.0%*
6476.6	6461.0	7257.2	7446.3	8377.6	8392.8	10032	10938	12657	12725	*13875*	*14425*	Total Capital ($mill)	*17100*
7838.0	7147.3	6442.0	8970.2	9809.9	10798	12462	13527	14336	14987	*16025*	*17075*	Net Plant ($mill)	*20300*
6.3%	7.0%	6.5%	6.3%	5.6%	6.7%	6.3%	6.3%	5.9%	6.3%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
10.1%	11.0%	10.8%	10.0%	9.5%	10.6%	10.9%	10.5%	10.6%	11.3%	*11.0%*	*11.5%*	Return on Shr. Equity	*11.5%*
10.3%	11.3%	11.2%	10.2%	9.7%	10.9%	11.2%	10.7%	10.8%	11.0%	*11.0%*	*11.5%*	Return on Com Equity E	*11.5%*
3.9%	4.9%	4.6%	3.6%	2.8%	4.0%	4.4%	4.2%	4.2%	4.3%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
64%	57%	60%	66%	72%	64%	62%	61%	62%	62%	*61%*	*61%*	All Div'ds to Net Prof	*61%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.2	-2.3	+3.7
Avg. Indust. Use (MWH)	11448	11134	NA
Avg. Indust. Revs. per KWH (¢)	6.98	7.55	7.64
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	5626	5496	5486
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.6	+.8
Fixed Charge Cov. (%)	265	251	259

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.0%	-.5%	*4.5%*
"Cash Flow"	7.0%	7.5%	*5.5%*
Earnings	7.0%	8.0%	*6.0%*
Dividends	6.5%	6.5%	*6.0%*
Book Value	5.5%	7.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	987.2	790.2	990.2	880.1	3647.7
2020	915.7	763.1	920.0	817.2	3416.0
2021	901	817	1024	927	3669.0
2022	1068	*900*	*1132*	*1000*	*4100*
2023	*1100*	*925*	*1175*	*1050*	*4250*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.53	.40	.94	.46	2.33
2020	.72	.54	.94	.26	2.47
2021	.68	.57	1.02	.35	2.63
2022	.77	*.60*	*1.05*	*.38*	*2.80*
2023	*.80*	*.65*	*1.10*	*.40*	*2.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.335	.335	.335	.335	1.34
2019	.355	.355	.355	.355	1.42
2020	.38	.38	.38	.38	1.52
2021	.4025	.4025	.4025	.4025	1.61
2022	.4275	.4275			

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 raported deprec. rates: 2.9%-6.1%. Has 3,300 employees. Chairman, President & CEO: John O. Larsen. Inc.: Wisconsin. Address: 4902 N. Billmore Lane, Madison, Wisconsin 53718-2148. Tel.: 608-458-3311. Internet: www.alliantenergy.com.

We have raised our 2022 earnings estimate for Alliant Energy by $0.05 a share, to $2.80. First-quarter earnings topped our $0.70-a-share estimate. The company benefited from favorable weather patterns and stronger-than-expected volume growth (aside from the weather effects) in the period. In addition, Alliant Energy's Wisconsin Power and Light subsidiary was granted rate relief at the start of the year. The utility received rate hikes of $114 million for electricity and $15 million for gas. Other positive factors are the addition of renewable-energy projects (see below), and effective control of operating and maintenance expenses, despite the inflationary environment. Our revised estimate is near the upper end of management's targeted range of $2.67-$2.81 a share.

We expect further profit growth in 2023. The company should benefit from rising volume growth (as long as the economy holds up) and income from additional renewable-energy projects. We think our previous estimate of $2.90 a share was too conservative, so we boosted it by a nickel. Alliant Energy's goal for annual earnings growth is 5%-7%.

The company is expanding its portfolio of renewable-energy projects. WPL is adding 325 megawatts of solar capacity this year, and has received approval for an additional 764 mw of solar capacity in 2023. However, the utility has not yet identified the sourcing for 500 mw in the second half of 2023. Given the supply-chain problems for solar panels, this is a source of uncertainty. Nevertheless, WPL plans to ask the regulators for permission to add up to 300 mw of additional solar capacity. Separately, the company is asking the Iowa commission for permission to add 400 mw of solar capacity along with 75 mw of battery storage. A decision is anticipated in the second half of 2022. These projects are expected to come on line in 2023 and 2024.

This equity has a high valuation. The dividend yield is below the utility average. Its prospects over the next 18 months and the 3- to 5-year period are subpar. Like many electric utility issues, the recent quotation is well within our 2025-2027 Target Price Range.

Paul E. Debbas, CFA *June 10, 2022*

(A) Diluted EPS. Excl. nonrecurring losses: '11, 1¢; '12, 8¢. '20 & '21 EPS don't sum due to rounding. Next earnings report due late July. (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	65
Earnings Predictability	95

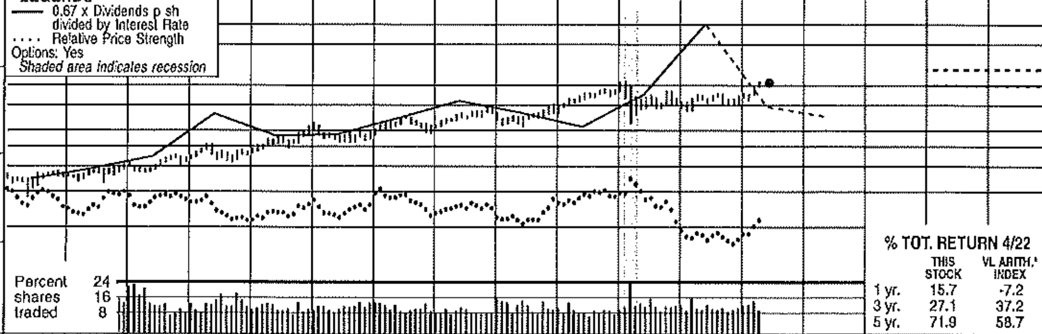
AMERICAN ELEC. PWR. NDQ-AEP

RECENT PRICE 103.57 | P/E RATIO 19.9 (Trailing: 19.8 Median: 17.0) | RELATIVE P/E RATIO 1.19 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 3 Raised 4/1/22
SAFETY 1 Raised 3/17/17
TECHNICAL 3 Lowered 6/10/22
BETA .75 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	41.7	45.4	51.6	63.2	65.4	71.3	78.1	81.1	96.2	105.0	91.5	104.8
Low:	33.1	37.0	41.8	45.8	52.3	56.8	61.8	62.7	72.3	65.1	74.8	84.2

LEGENDS
— 0.67 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)
$83-$115 $99 (-5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	120	(+15%)	7%
Low	100	(-5%)	3%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	561	636	673
to Sell	433	473	475
Hld's(000)	373255	373909	382433

Percent shares traded 24 16 8

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	15.7	-7.2
3 yr.	27.1	37.2
5 yr.	71.9	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB, LLC	25-27
31.82	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	*35.20*	*35.95*	Revenues per sh	*38.50*
6.67	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	*11.50*	*11.95*	"Cash Flow" per sh	*14.00*
2.86	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	*5.20*	*5.35*	Earnings per sh A	*6.50*
1.50	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*	Div'd Decl'd per sh B ■ †	*4.00*
8.89	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	*15.35*	*14.15*	Cap'l Spending per sh	*14.00*
23.73	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	*47.30*	*50.30*	Book Value per sh C	*59.00*
396.67	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	*514.00*	*523.00*	Common Shs Outst'g D	*545.00*
12.9	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	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.70	.87	.79	.67	.85	.75	.88	.81	.84	.80	.80	.97	.97	1.14	1.01	.93	*Value Line*		Relative P/E Ratio	*.95*
4.1%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $37244 mill. Due in 5 Yrs $12886 mill.
LT Debt $30856 mill. LT Interest $1067 mill.
Incl. $603.5 mill. securitized bonds. Incl. $500.7 mill. finance leases.
(LT interest earned: 3.2x)
Leases, Uncapitalized Annual rentals $119.6 mill.
Pension Assets-12/21 $5352.9 mill.
Oblig $5187.0 mill.
Pfd Stock None

Common Stock 513,544,176 shs. as of 4/28/22
MARKET CAP: $53 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
14945	15357	17020	16453	16380	15425	16196	15561	14919	16792	*18100*	*18800*	Revenues ($mill)	*21000*
1443.0	1549.0	1634.0	1763.4	2073.6	1783.2	1923.8	2019.0	2200.1	2488.1	*2670*	*2790*	Net Profit ($mill)	*3565*
33.9%	36.2%	37.8%	35.1%	26.8%	33.7%	5.8%	.7%	1.9%	4.6%	*7.0%*	*7.0%*	Income Tax Rate	*7.0%*
11.2%	7.3%	9.0%	11.0%	8.0%	8.0%	10.7%	12.7%	9.7%	7.8%	*7.0%*	*7.0%*	AFUDC % to Net Profit	*5.0%*
50.6%	51.1%	49.0%	49.8%	50.0%	51.5%	53.2%	56.1%	58.5%	58.3%	*58.0%*	*58.0%*	Long-Term Debt Ratio	*57.5%*
49.4%	48.9%	51.0%	50.2%	50.0%	48.5%	46.8%	43.9%	41.5%	41.7%	*42.0%*	*42.0%*	Common Equity Ratio	*42.5%*
30823	32913	33001	35633	34775	37707	40677	44759	49537	53734	*57775*	*62950*	Total Capital ($mill)	*75900*
38763	40997	44117	46133	45639	50262	55099	60138	63902	66001	*70650*	*74600*	Net Plant ($mill)	*87300*
6.1%	6.0%	6.3%	6.1%	7.2%	5.9%	5.9%	5.6%	5.6%	5.6%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	*11.0%*	*10.5%*	Return on Shr. Equity	*11.0%*
9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	*11.0%*	*10.5%*	Return on Com Equity E	*11.0%*
3.5%	3.7%	3.8%	3.9%	5.5%	3.2%	3.5%	3.4%	3.8%	4.3%	*4.5%*	*4.0%*	Retained to Com Eq	*4.5%*
63%	62%	61%	60%	54%	67%	65%	67%	65%	61%	*63%*	*64%*	All Div'ds to Net Prof	*62%*

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 '19-'21 to '25-'27
Revenues	.5%	-1.5%	*3.5%*
"Cash Flow"	4.5%	5.0%	*5.5%*
Earnings	4.5%	4.0%	*6.5%*
Dividends	5.0%	6.0%	*6.0%*
Book Value	4.0%	3.5%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	4056	3573	4315	3616	15561
2020	3747	3494	4066	3610	14918
2021	4281	3826	4623	4061	16792
2022	4593	*4107*	*4950*	*4450*	*18100*
2023	*4800*	*4300*	*5150*	*4550*	*18800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.16	.93	1.48	.51	4.08
2020	1.00	1.05	1.50	.87	4.42
2021	1.15	1.15	1.59	1.07	4.96
2022	1.41	*1.15*	*1.64*	*1.00*	*5.20*
2023	*1.30*	*1.25*	*1.75*	*1.05*	*5.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.62	.62	.62	.67	2.53
2019	.67	.67	.67	.70	2.71
2020	.70	.70	.70	.74	2.84
2021	.74	.74	.74	.78	3.00
2022	.78	.78			

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. '21 reported depreciation rates (utility): 2.6%-12.5%. Has 16,700 employees. Chairman, President & CEO: Nicholas K. Akins. COO: Lisa Barton. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

American Electric Power should soon complete an asset sale, and the company is interested in divesting other assets. AEP expects to raise $1.45 billion from the sale of its Kentucky Power subsidiary, which has not been earning an adequate return on equity. This is expected to be completed by the end of this month. The company also wants to sell its 1,600-megawatt portfolio of nonregulated renewable-energy projects, either piecemeal or as a whole. We will *include* any gains on these sales in our earnings presentation. AEP plans to expand its investments in regulated renewable-energy projects, which have less risk than non-utility assets, and electric transmission.

We expect respectable earnings growth in 2022 and 2023. We raised our estimate for this year by $0.20 a share, to $5.20, thanks to a $0.20 mark-to-market credit that AEP booked in the first quarter. Our revised estimate is within management's guidance (on a GAAP basis) of $5.06-$5.26 a share. Otherwise, the company should continue to benefit from rate relief, increased investment in its transmission business, and volume growth. Some industrial customers in its service area have expansions that are expected to come on later this year, despite the state of the national economy.

Some regulatory matters are pending or were concluded. The SWEPCO subsidiary was granted $28 million in Arkansas, based on a 9.5% return on equity and a 45% common-equity ratio. New tariffs will take effect on July 1st. In Louisiana, the utility requested $73 million, based on a 10.35% ROE and a 50.8% common-equity ratio. (This is net of increases in depreciation and amortization.) In Virginia, Appalachian Power is appealing an unfavorable rate order to the state Supreme Court. A decision is expected later in 2022. Note that the company has already received rate increases in Texas and Indiana this year.

The dividend yield of this top-quality stock is at the utility average. Total return potential is unspectacular for the next 18 months and the 3- to 5-year period. The recent quotation is within our 2025-2027 Target Price Range. The stock price has risen 16% year to date.

Paul E. Debbas, CFA *June 10, 2022*

(A) Diluted EPS. Excl. nonrec. gains (losses): '06, (20¢); '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¢). 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 '21: $17.04/sh. (D) In mill. (E) Rate base: various. Rates allowed on com. eq.: 9.3%-10.9%; earned on avg. com. eq., '21: 11.6%. Regulatory Climate: Average.

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

AMEREN NYSE-AEE

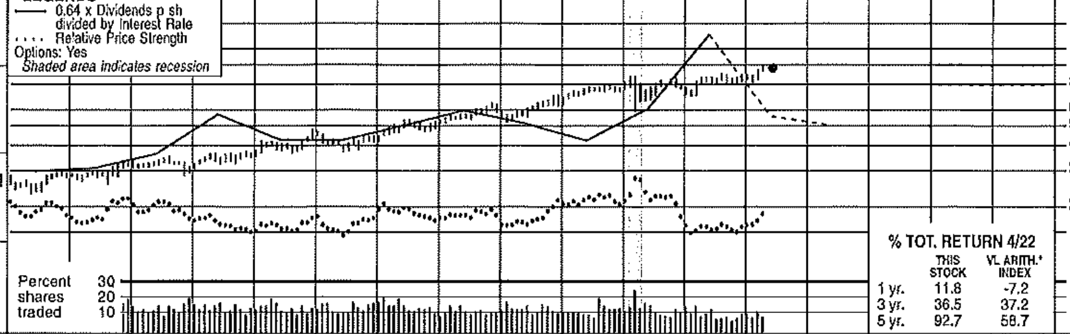
RECENT PRICE 96.55 | P/E RATIO 23.5 (Trailing: 24.8 / Median: 19.0) | RELATIVE P/E RATIO 1.41 | DIV'D YLD 2.5% | VALUE LINE

TIMELINESS 4 Raised 4/22/22
SAFETY 1 Raised 9/10/21
TECHNICAL 2 Lowered 6/3/22
BETA .80 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	34.1	35.3	37.3	48.1	46.8	54.1	64.9	70.9	80.9	87.7	90.8	99.2
Low:	25.5	28.4	30.6	35.2	37.3	41.5	51.4	51.9	63.1	58.7	69.8	81.8

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

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$86-$124 $105 (10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+5%)	4%
Low	80	(-15%)	-1%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	248	308	294
to Sell	246	227	262
Hld's(000)	199566	198495	200507

Percent shares traded 30 20 10

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	11.8	-7.2
3 yr.	36.5	37.2
5 yr.	92.7	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
33.30	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	27.45	28.10	Revenues per sh	30.00
6.02	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	9.50	10.05	"Cash Flow" per sh	11.75
2.66	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	4.10	4.35	Earnings per sh A	5.25
2.54	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	Div'd Decl'd per sh B ■	3.10
4.99	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	12.90	12.55	Cap'l Spending per sh	13.00
31.86	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	40.20	42.90	Book Value per sh C	51.25
206.60	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	262.50	267.00	Common Shs Outst'g D	280.00
19.4	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	Bold figures are		Avg Ann'l P/E Ratio	17.5
1.05	.92	.85	.62	.62	.75	.85	.93	.88	.88	.96	1.04	.99	1.18	1.14	1.14	Value Line		Relative P/E Ratio	.95
4.9%	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%	estimates		Avg Ann'l Div'd Yield	3.4%

CAPITAL STRUCTURE as of 3/31/22
Total Debt $14169 mill. Due in 5 Yrs $3446 mill.
LT Debt $12563 mill. LT Interest $436 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.; 467,508 sh. 4.00% to 5.16%, $100 par, redeem. $100-$104.30/sh.
Common Stock 258,226,506 shs. as of 4/29/22
MARKET CAP: $25 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
6828.0	5838.0	6053.0	6098.0	6076.0	6177.0	6291.0	5910.0	5794.0	6394.0	7200	7500	Revenues ($mill)	8400
589.0	518.0	593.0	585.0	659.0	683.0	821.0	834.0	877.0	995.0	1075	1165	Net Profit ($mill)	1455
36.9%	37.5%	38.9%	38.3%	36.7%	38.2%	22.4%	17.9%	15.0%	13.6%	12.0%	12.0%	Income Tax Rate	12.0%
6.1%	7.1%	5.7%	5.1%	4.1%	5.6%	6.9%	5.8%	5.5%	6.0%	6.0%	5.0%	AFUDC % to Net Profit	4.0%
49.5%	45.2%	47.2%	49.3%	47.7%	49.2%	50.3%	52.1%	55.0%	56.1%	55.5%	53.5%	Long-Term Debt Ratio	51.0%
49.4%	53.7%	51.7%	49.7%	51.3%	49.8%	48.8%	47.1%	44.3%	43.3%	44.0%	46.0%	Common Equity Ratio	48.5%
13384	12190	12975	13968	13840	14420	15632	17116	20158	22391	23900	24950	Total Capital ($mill)	29500
16096	16205	17424	18799	20113	21466	22810	24376	26807	29261	31225	33050	Net Plant ($mill)	38400
6.0%	5.6%	5.8%	5.3%	6.0%	6.0%	6.4%	6.0%	5.3%	5.3%	5.5%	5.5%	Return on Total Cap'l	6.0%
8.7%	7.7%	8.7%	8.3%	9.1%	9.3%	10.6%	10.2%	9.7%	10.1%	10.0%	10.0%	Return on Shr. Equity	10.0%
8.8%	7.8%	8.7%	8.3%	9.2%	9.4%	10.7%	10.3%	9.7%	10.2%	10.0%	10.0%	Return on Com Equity E	10.0%
3.0%	1.9%	2.9%	2.5%	3.3%	3.4%	4.8%	4.4%	4.2%	4.4%	4.5%	4.5%	Retained to Com Eq	4.0%
66%	76%	67%	70%	64%	64%	56%	57%	57%	57%	58%	58%	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 '19-'21 to '25-'27
Revenues	-2.5%	-1.0%	4.0%
"Cash Flow"	3.0%	6.0%	6.0%
Earnings	3.0%	7.5%	6.5%
Dividends	3.0%	4.0%	7.0%
Book Value	1.0%	4.5%	6.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1556	1379	1659	1316	5910
2020	1440	1398	1628	1328	5794
2021	1566	1472	1811	1545	6394
2022	1879	1621	2000	1700	7200
2023	1900	1700	2100	1800	7500

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.78	.72	1.47	.38	3.35
2020	.59	.98	1.47	.46	3.50
2021	.91	.80	1.65	.48	3.84
2022	.97	.85	1.78	.50	4.10
2023	.95	.90	1.95	.55	4.35

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.4575	.4575	.4575	.475	1.85
2019	.475	.475	.475	.495	1.92
2020	.495	.495	.495	.515	2.00
2021	.55	.55	.55	.55	2.20
2022	.59	.59			

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. '21 reported deprec. rates: 3%-4%. Has 9,100 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's earnings will probably rise solidly in 2022. A key factor will be electric and gas rate increases ($220 million and $5 million, respectively) that took effect in Missouri on February 28th. The company will pick up a few cents a share from a full year's effect of a gas tariff hike in Illinois last year. Ameren also benefits annually from growth in its rate base for electric transmission (federally regulated) and for electricity in Illinois through formula rate plans. Our share-earnings estimate remains at $4.10, which is within the company's targeted range of $3.95-$4.15.

We expect further profit growth in 2023. Income will include a full year's effect of the Missouri rate hikes. Ameren will obtain additional rate relief from its transmission and Illinois electric operations. Management's goal for annual earnings growth is 6%-8%, and our estimate of $4.35 a share would produce an increase of 6% from our estimated 2022 tally.

Our estimates are based on Ameren maintaining its allowed return on equity for transmission. The Federal Energy Regulatory Commission (FERC) is thinking of eliminating a half percentage point incentive "adder" that makes its allowed ROE 10.52%. This would reduce annual profits by a nickel a share. The timing of FERC's decision is unknown.

Financing needs are significant. Ameren plans to issue about $300 million of common equity annually through 2026, over and above the equity issued via its dividend-reinvestment and other stock plans (roughly $100 million a year). The company is issuing debt, as well.

Ameren plans to close a coal-fired plant. The facility is 45 years old, so adding court-ordered (and costly) pollution-control equipment wouldn't be prudent. The Midcontinent Independent System Operator is studying how the plant's retirement will affect reliability in the region. The utility intends to recover its investment in the plant by issuing securitized bonds. This will require the approval of the regulatory commission in Missouri.

The dividend yield of this untimely but high-quality stock is below the utility mean. The recent quotation is well within our 2025-2027 Target Price Range. Accordingly, total return potential is low.

Paul E. Debbas, CFA *June 10, 2022*

(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 Aug. (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	75
Earnings Predictability	95

AVANGRID, INC. NYSE-AGR

RECENT PRICE 43.83 | P/E RATIO 19.1 (Trailing: 20.5, Median: NMF) | RELATIVE P/E RATIO 1.15 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 4 Raised 5/6/22
SAFETY 2 Raised 2/17/17
TECHNICAL 4 Raised 5/13/22
BETA .85 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$41-$62 $52 (20%)

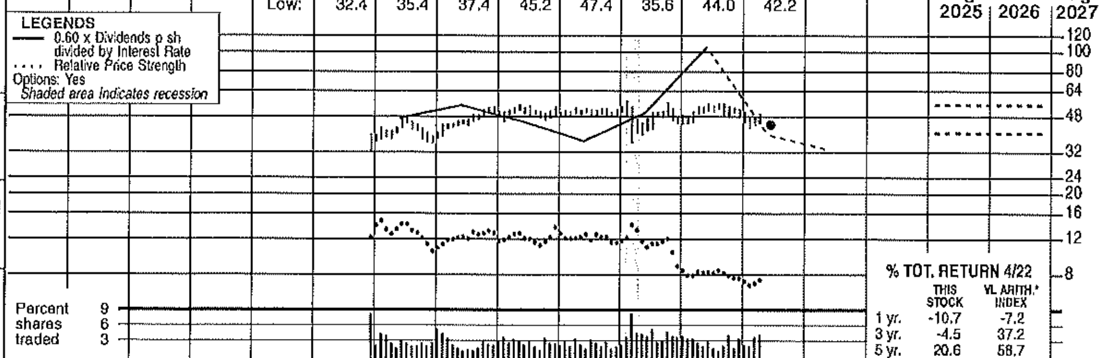
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+25%)	9%
Low	40	(-10%)	2%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	144	128	138
to Sell	120	110	125
Hld's(000)	41701	41507	43102

	2015	2016	2017	2018	2019	2020	2021	2022
High:	30.9	46.7	53.5	54.6	52.9	57.2	55.6	50.7
Low:	32.4	35.4	37.4	45.2	47.4	35.6	44.0	42.2



% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-10.7	-7.2
3 yr.	-4.5	37.2
5 yr.	20.6	58.7

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 incorporated in 1997 in New York under the name NGE Resources, Inc. AVANGRID began trading on the NYSE on December 17, 2015.

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
--	--	--	14.14	19.48	19.30	20.96	20.51	20.45	18.04	19.15	19.55	Revenues per sh	21.50
--	--	--	3.44	4.74	4.49	4.89	5.50	5.07	4.45	5.05	4.95	"Cash Flow" per sh	5.75
--	--	--	1.05	1.98	1.67	1.92	2.26	1.88	1.97	2.30	2.05	Earnings per sh A	2.50
--	--	--	--	1.73	1.73	1.74	1.76	1.76	1.76	1.76	1.76	Div'd Decl'd per sh B ■	1.90
--	--	--	3.50	5.52	7.82	5.78	8.87	9.00	7.70	8.30	8.65	Cap'l Spending per sh	9.50
--	--	--	48.74	48.90	48.79	48.88	49.31	49.21	49.35	49.90	50.15	Book Value per sh C	51.50
--	--	--	308.86	308.99	309.01	309.01	309.01	309.08	386.57	386.60	386.60	Common Shs Outst'g D	386.60
--	--	--	33.5	20.5	27.3	26.1	22.1	25.3	25.7	Bold figures are	Value Line	Avg Ann'l P/E Ratio	19.0
--	--	--	1.69	1.08	1.37	1.41	1.18	1.30	1.40	estimates		Relative P/E Ratio	1.05
--	--	--	--	4.3%	3.8%	3.5%	3.5%	3.7%	3.5%			Avg Ann'l Div'd Yield	4.0%
--	--	4594.0	4367.0	6018.0	5963.0	6478.0	6338.0	6320.0	6974.0	7400	7550	Revenues ($mill)	8300
--	--	424.0	267.0	611.0	516.0	595.0	700.0	581.0	707.0	890	795	Net Profit ($mill)	935
--	--	39.9%	11.3%	37.4%	32.4%	22.1%	17.5%	5.1%	3.2%	7.0%	7.0%	Income Tax Rate	7.0%
--	--	6.8%	12.7%	7.5%	12.4%	9.4%	14.4%	18.4%	17.1%	15.0%	17.0%	AFUDC % to Net Profit	15.0%
--	--	16.8%	23.1%	23.0%	25.6%	26.2%	30.6%	40.8%	29.3%	31.5%	33.0%	Long-Term Debt Ratio	38.5%
--	--	83.2%	76.9%	77.0%	74.4%	73.8%	69.4%	59.2%	70.7%	68.5%	67.0%	Common Equity Ratio	61.5%
--	--	14956	19583	19619	20273	20472	21953	25687	26998	28150	29025	Total Capital ($mill)	32400
--	--	17099	20711	21548	22669	23459	25218	26751	28866	31000	33250	Net Plant ($mill)	40400
--	--	3.7%	2.1%	3.8%	3.1%	3.5%	3.8%	2.8%	3.1%	3.5%	3.5%	Return on Total Cap'l	3.5%
--	--	3.4%	1.8%	4.0%	3.4%	3.9%	4.6%	3.8%	3.7%	4.5%	4.0%	Return on Shr. Equity	4.5%
--	--	3.4%	1.8%	4.0%	3.4%	3.9%	4.6%	3.8%	3.7%	4.5%	4.0%	Return on Com Equity E	4.5%
--	--	3.4%	1.8%	1.4%	NMF	.4%	1.0%	.2%	.5%	1.0%	.5%	Retained to Com Eq	1.0%
--	--	--	--	66%	104%	90%	78%	94%	87%	77%	86%	All Div'ds to Net Prof	79%

CAPITAL STRUCTURE as of 3/31/22
Total Debt $8349 mill. Due in 5 Yrs $3225 mill.
LT Debt $8033 mill. LT Interest $300 mill.
Incl. $95 mill. finance leases.
(LT interest earned: 3.1x)
Leases, Uncapitalized Annual rentals $14 mill.

Pension Assets-12/21 $3079 mill. Oblig $3487 mill.
Pfd Stock None

Common Stock 386,624,231 shs.
as of 4/28/22
MARKET CAP: $17 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% 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)	+.8	+.9	+.1
Fixed Charge Cov. (%)	278	237	270

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	--	3.0%	1.5%
"Cash Flow"	--	4.0%	2.5%
Earnings	--	6.0%	3.5%
Dividends	--	15.5%	1.5%
Book Value	--	--	.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1842	1400	1487	1609	6338.0
2020	1789	1392	1470	1669	6320.0
2021	1966	1477	1598	1933	6974.0
2022	2133	1567	1700	2000	7400
2023	2150	1600	1750	2050	7550

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.70	.36	.48	.72	2.26
2020	.78	.28	.28	.54	1.88
2021	1.08	.28	.29	.42	1.97
2022	1.15	.25	.40	.50	2.30
2023	.85	.25	.40	.55	2.05

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.432	.432	.432	.44	1.74
2019	.44	.44	.44	.44	1.76
2020	.44	.44	.44	.44	1.76
2021	.44	.44	.44	.44	1.76
2022	.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 power, with 8.5 gigawatts of capacity. Revenue breakdown by customer class not available. Generating sources not available. Fuel costs: 25% of revenues. '21 reported depr. rate (utility): 2.8%. Iberdrola owns 81.5% of stock. Has 7,300 employees. Chairman: José Ignacio Sanchez Galan. CEO: Dennis V. Arriola. Deputy CEO & President: Robert Kump. Inc.: NY. Address: 180 Marsh Hill Road, Orange, CT 06477. Tel.: 207-629-1200. Web: www.avangrid.com.

We have raised our 2022 share-net estimate for AVANGRID from $1.95 to $2.30. This is near the midpoint of the company's guidance of $2.20-$2.38. First-quarter profits topped our $0.80-a-share estimate. However, the key factor was a restructuring of an offshore wind joint-venture partnership, which now has AVANGRID taking full ownership of some projects. This resulted in a $181 million aftertax gain. We are *including* this in our earnings presentation, but because this income is unusual, we estimate that the company's earnings will decline in 2023. Investors should note that the Renewables division faces uncertainties about solar energy due to inflation, possible tariff increases, and supply chain delays. The stock price is down 12% year to date.

Two key legal matters are pending. AVANGRID has agreed to acquire PNM Resources (the parent of electric utilities in New Mexico and Texas) for $4.3 billion in cash. However, the New Mexico commission rejected the proposed combination. The companies have appealed the ruling to the New Mexico Supreme Court, and extended the merger agreement to April 20, 2023. Our estimates and projections do not include PNM Resources. AVANGRID is appealing a referendum in Maine that requires the legislature to approve a transmission line in the state. A decision from the Maine Supreme Court is expected this summer. As of March 31st, the company had spent $561 million on the project, with a total expected cost of $1.2 billion. If construction resumes in 2022, completion is expected in the second half of 2024.

Central Maine Power got some good news. Due to the utility's improved service, the state regulators removed a one-percentage-point penalty that had been imposed on the allowed return on equity. This raised the allowed ROE to 9.25%.

AVANGRID is adding offshore wind projects. Its first project is under construction. Capital spending contracts are mitigating current inflationary pressures, but there is still construction risk.

The stock is untimely, but has a dividend yield that is above the utility mean. The drawbacks are subpar dividend growth potential and (mostly) difficult regulatory climates.

Paul E. Debbas, CFA *May 13, 2022*

(A) Diluted EPS. Excl. nonrecurring gain (loss): '16, 6¢; '17, (44¢). '21 EPS don't sum to full-year total due to change in shares outstanding. Next earnings report due late July. (B) Div'ds paid in early Jan., April, July, and Oct. ■ Dividend reinvestment plan available. (C) Incl. intangibles. In '21: $5659 mill., $14.64/sh. (D) In millions. (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%; earned on avg. common eq., '21: 4.1%. Regulatory Climate: Below Average.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	50
Earnings Predictability	75

AVISTA CORP. NYSE-AVA

RECENT PRICE	42.52	P/E RATIO	21.8 (Trailing: 20.2 / Median: 19.0)	RELATIVE P/E RATIO	1.42	DIV'D YLD	4.1%	VALUE LINE

TIMELINESS 3 Raised 6/10/22
SAFETY 2 Raised 5/7/10
TECHNICAL 3 Lowered 7/22/22
BETA .90 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	26.5	28.0	29.3	37.4	38.3	45.2	52.8	52.9	49.5	53.0	49.1	46.9
Low:	21.1	22.8	24.1	27.7	29.8	34.3	37.8	41.9	39.8	32.1	36.7	39.4

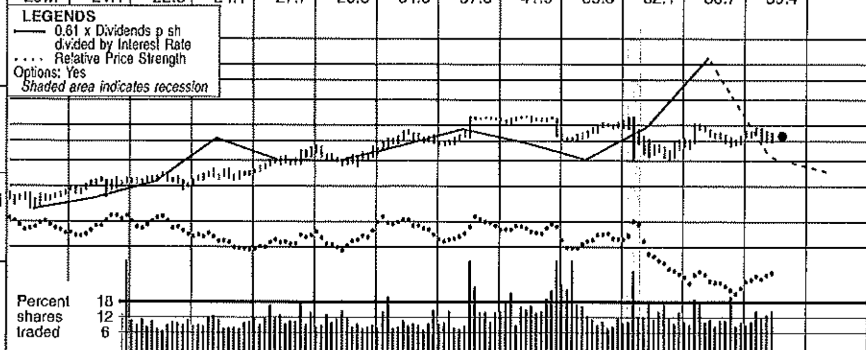
18-Month Target Price Range
Low-High $38-$55 Midpoint (% to Mid) $47 (10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+55%)	14%
Low	45	(+5%)	5%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	118	142	136
to Sell	103	102	108
Hld's(000)	57202	58479	60407



Target Price Range 2025 | 2026 | 2027
128
96
80
64
48
40
32
24
16
12

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-7.7	-7.2
3 yr.	5.5	37.2
5 yr.	19.9	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
28.68	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	19.85	20.40	Revenues per sh	21.10
4.27	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	5.25	5.80	"Cash Flow" per sh	6.50
1.47	.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	1.95	2.45	Earnings per sh A	2.75
.57	.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	1.83	Div'd Decl'd per sh B ■	2.05
3.14	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	6.25	6.10	Cap'l Spending per sh	5.75
17.46	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	30.85	31.75	Book Value per sh C	34.75
52.51	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	74.50	77.00	Common Shs Outst'g D	83.00
15.4	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	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	20.0
.83	1.64	.90	.76	.81	.88	1.23	.82	.91	.89	.99	1.18	1.32	.80	1.09	1.11			Relative P/E Ratio	1.10
2.5%	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%			Avg Ann'l Div'd Yield	3.7%
						1547.0	1618.5	1472.6	1484.8	1442.5	1445.9	1396.9	1345.6	1321.9	1438.9	1480	1570	Revenues ($mill)	1750
						78.2	111.1	114.2	118.1	137.2	126.1	136.4	197.0	129.5	147.3	145	190	Net Profit ($mill)	230
						34.4%	36.0%	37.6%	36.3%	36.3%	36.5%	16.0%	13.8%	5.2%	7.5%	15.0%	15.0%	Income Tax Rate	15.0%
						8.3%	8.8%	11.1%	10.1%	8.1%	7.9%	7.7%	5.5%	8.5%	7.5%	8.0%	6.0%	AFUDC % to Net Profit	5.0%
						50.8%	51.4%	51.0%	50.0%	51.2%	47.2%	50.5%	49.4%	50.4%	47.5%	50.5%	50.0%	Long-Term Debt Ratio	48.5%
						49.2%	48.6%	49.0%	50.0%	48.8%	52.8%	49.5%	50.6%	49.6%	52.5%	49.5%	50.0%	Common Equity Ratio	51.5%
						2561.2	2669.7	3027.3	3060.3	3379.0	3273.2	3580.3	3834.6	4089.8	4104.7	4635	4875	Total Capital ($mill)	5630
						3023.7	3202.4	3620.0	3898.6	4147.5	4398.8	4648.9	4797.0	4991.6	5225.5	5420	5640	Net Plant ($mill)	6175
						4.3%	5.4%	4.9%	5.1%	5.3%	5.0%	4.8%	6.2%	4.2%	4.7%	4.0%	5.0%	Return on Total Cap'l	5.0%
						6.2%	8.6%	7.7%	7.7%	8.3%	7.3%	7.7%	10.2%	6.4%	6.8%	6.5%	7.5%	Return on Shr. Equity	8.0%
						6.2%	8.6%	7.7%	7.7%	8.3%	7.3%	7.7%	10.2%	6.4%	6.8%	6.5%	7.5%	Return on Com Equity E	8.0%
						.8%	2.9%	2.4%	2.3%	3.0%	1.9%	2.2%	4.9%	.9%	1.4%	.5%	2.0%	Retained to Com Eq	2.0%
						88%	66%	69%	70%	64%	73%	72%	52%	85%	80%	90%	75%	All Div'ds to Net Prof	75%

CAPITAL STRUCTURE as of 3/31/22
Total Debt $2595.7 mill. **Due in 5 Yrs** $650.0 mill.
LT Debt $2345.7 mill. **LT Interest** $94.0 mill.
Incl. $51.5 mill. debt to affiliated trusts; $48.8 mill. finance leases.
(LT interest earned: 2.6x)
Leases, Uncapitalized Annual rentals $4.8 mill.
Pension Assets-12/21 $751.0 mill.
Oblig $799.0 mill.
Pfd Stock None

Common Stock 72,439,910 shs. as of 4/30/22
MARKET CAP: $3.1 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+.8	-2.4	+4.3
Avg. Indust. Use (MWH)	1296	1265	1383
Avg. Indust. Revs. per KWH (¢)	6.26	6.38	6.41
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	1656	1721	1889
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.3	+1.8	+1.4
Fixed Charge Cov. (%)	202	221	215

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-3.5%	-3.5%	1.0%
"Cash Flow"	3.5%	2.5%	3.0%
Earnings	3.5%	3.5%	3.0%
Dividends	5.5%	4.0%	4.0%
Book Value	4.0%	3.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	396.5	300.8	283.8	364.5	1345.6
2020	390.2	278.6	272.6	380.5	1321.9
2021	412.9	298.2	296.0	431.8	1438.9
2022	462.0	315	305	398	1480
2023	485	340	325	420	1570

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.76	.38	.08	.76	2.97
2020	.72	.26	.07	.85	1.90
2021	.98	.20	.20	.71	2.10
2022	.99	.20	.15	.61	1.95
2023	1.10	.35	.25	.75	2.45

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.3725	.3725	.3725	.3725	1.49
2019	.3875	.3875	.3875	.3875	1.55
2020	.405	.405	.405	.405	1.62
2021	.4225	.4225	.4225	.4225	1.69
2022	.44	.44			

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: 423,000 electric, 372,000 gas. Acq'd Alaska Electric Light and Power 7/14. Sold Ecova energy-management sub. 6/14. Electric rev. breakdown: residential, 41%; commercial, 34%; industrial, 11%; wholesale, 9%; other, 5%. Generating sources: gas & coal, 30%; hydro, 29%; purch., 41%. Fuel costs: 35% of revs. '21 reported depr. rate (Avista Utilities): 3.5%. Has 1,900 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 reached a multiparty settlement in its Washington rate case. The Spokane utility reached an agreement that is now under review by regulators. The deal would include two separate increases that would raise electricity rates by 7.7% during the next two years and boost natural gas rates by 1.1% over that span. The hikes would begin on December 1st of this year, and the actual raises would vary depending on the customer and the level of usage. The settlement is tied to the company's rate plan filed in January that asked for 11% and 4.3% boosts over the next two years among electric and natural gas rates, respectively. If approved, Avista's electric revenues in the state would rise by $50 million over the next two years and natural gas receipts would be $9 million higher.

The agreement includes a residual tax customer credit. This part of the pact eases the affects on customers by offsetting part of the rate request. The credit here is expected to incrementally return $27.6 million to electric customers, while natural gas patrons would get $12.5 million. The time frame for this credit stretches through December of 2024.

We continue to look for an earnings dip in 2022, followed by a jump in 2023. In 2021, Avista was aided by favorable power costs in Washington that are now no longer in play. Too, the contribution from nonutility investments was elevated and we do not see that happening again this year. Add to this, the share count has moved higher. All told, our 2022 EPS target is now a hair below the $2.00 line. Next year, rate increases should be in full swing in Washington, Idaho, and Oregon, with the possibility that Alaskan rate relief is on the way, as well. With that, we are maintaining our $2.45 earnings-per-share call, which falls in the bottom half of management's guidance. At such earnings levels, we expect the currently elevated payout ratio to return to its target level of between 65% and 75%.

This neutrally ranked stock has a yield that is above average for a utility. But, total return potential over the coming 18 months is unexciting, and over the stretch to 2025-2027 that reading is noticeably below the *Value Line* average.

Erik M. Manning *July 22, 2022*

(A) Diluted EPS. Excl. nonrec. gain (loss): '14, 9¢; '17, (16¢); gains on discont. ops.: '14, $1.17; '15, 8¢. '19 & '21 EPS don't sum due to rounding. Next earnings report due early August. (B) Div'ds paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. deferred chgs. In '21: $913.1 mill., $19.22/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., '21: 7.1%. Regulatory Climate: WA, Below Average; ID, Above Average.

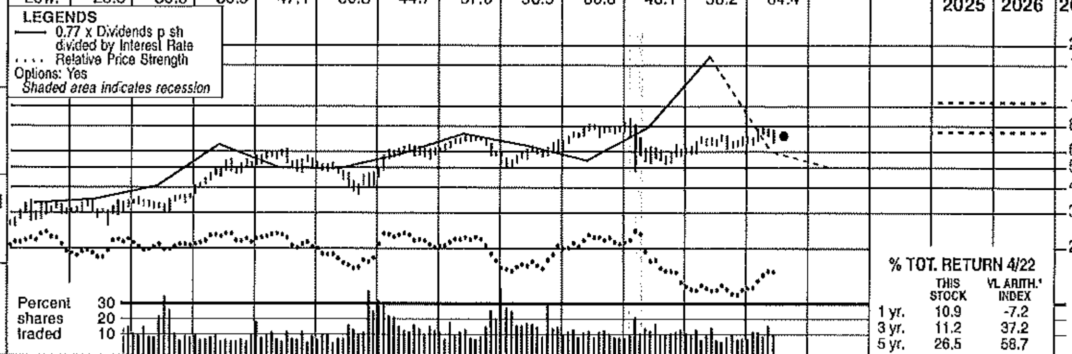
Company's Financial Strength	B++
Stock's Price Stability	70
Price Growth Persistence	40
Earnings Predictability	65

BLACK HILLS CORP. NYSE-BKH

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
71.90	17.5 (Trailing: 17.8) (Median: 18.0)	1.14	3.3%	

TIMELINESS 3 Raised 5/20/22
SAFETY 2 Raised 5/1/15
TECHNICAL 2 Raised 7/1/22
BETA .95 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	34.8	37.0	55.1	62.1	53.4	64.6	72.0	68.2	82.0	87.1	72.8	80.9
Low:	25.8	30.3	36.9	47.1	36.8	44.7	57.0	50.5	60.8	48.1	58.2	64.4



Target Price Range 2025 | 2026 | 2027

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$59-$88	$74 (1%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+45%)	13%
Low	75	(+5%)	5%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	120	168	152
to Sell	129	105	139
Hld's(000)	55119	55367	57141

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	10.9	-7.2
3 yr.	11.2	37.2
5 yr.	26.5	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
19.69	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	*32.80*	*32.95*	Revenues per sh	*33.10*
5.04	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	*7.75*	*8.15*	"Cash Flow" per sh	*9.45*
2.21	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	*4.10*	*4.30*	Earnings per sh A	*5.20*
1.32	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*	Div'd Decl'd per sh B ■	*2.95*
9.24	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	*8.50*	*8.75*	Cap'l Spending per sh	*9.50*
23.68	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	*43.60*	*44.45*	Book Value per sh C	*46.50*
33.37	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	*66.50*	*67.50*	Common Shs Outst'g D	*71.00*
15.8	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	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
.85	.80	NMF	.66	1.15	1.95	1.09	1.02	1.00	.81	1.17	.98	.91	1.13	.87	.97	*Value Line*		Relative P/E Ratio	*.95*
3.8%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $4469.8 mill. Due in 5 Yrs $1800.0 mill.
LT Debt $4128.3 mill. LT Interest $148.0 mill.
(LT interest earned: 2.9x)
Leases, Uncapitalized Annual rentals $2.2 mill.

Pension Assets-12/21 $458.4 mill. Oblig $478.3 mill.

Pfd Stock None

Common Stock 64,833,223 shs. as of 4/29/22

MARKET CAP: $4.7 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
1173.9	1275.9	1393.6	1304.6	1573.0	1680.3	1754.3	1734.9	1696.9	1949.1	*2180*	*2225*	Revenues ($mill)	*2350*
86.9	115.8	128.8	128.3	140.3	186.5	192.5	214.5	232.9	236.7	*275*	*290*	Net Profit ($mill)	*370*
35.5%	34.7%	33.7%	35.8%	25.1%	28.7%	19.2%	13.0%	12.2%	2.8%	*8.5%*	*8.5%*	Income Tax Rate	*8.5%*
5.4%	2.4%	2.4%	2.7%	5.3%	2.7%	1.4%	3.3%	2.5%	2.0%	*2.0%*	*1.0%*	AFUDC % to Net Profit	*1.0%*
43.2%	51.6%	47.9%	56.0%	66.5%	64.5%	57.5%	57.1%	57.9%	59.7%	*57.0%*	*55.0%*	Long-Term Debt Ratio	*45.0%*
56.8%	48.4%	52.1%	44.0%	33.5%	35.5%	42.5%	42.9%	42.1%	40.3%	*43.0%*	*45.0%*	Common Equity Ratio	*55.0%*
2171.4	2704.7	2643.6	3332.7	4825.8	4818.4	5132.4	5502.2	6089.5	6914.0	*6900*	*7000*	Total Capital ($mill)	*7300*
2742.7	2990.3	3239.4	3259.1	4469.0	4541.4	4854.9	5503.2	6019.7	6449.2	*6800*	*7100*	Net Plant ($mill)	*8200*
5.5%	5.5%	6.1%	4.9%	4.0%	5.2%	5.0%	4.9%	5.0%	4.5%	*5.0%*	*5.0%*	Return on Total Cap'l	*6.0%*
7.1%	8.9%	9.4%	8.8%	8.7%	10.9%	8.8%	9.1%	9.1%	8.5%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.0%*
7.1%	8.9%	9.4%	8.8%	8.7%	10.9%	8.8%	9.1%	9.1%	8.5%	*9.5%*	*9.5%*	Return on Com Equity E	*10.0%*
1.8%	3.7%	4.3%	3.8%	3.3%	5.3%	3.9%	3.8%	3.8%	3.3%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
75%	58%	54%	57%	62%	52%	55%	56%	58%	61%	*59%*	*59%*	All Div'ds to Net Prof	*57%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+2.1	-.7	+1.5
Avg. Indust. Use (MWH)	21406	21624	21358
Avg. Indust. Revs. per KWH (¢)	7.38	7.31	8.51
Capacity at Yearend (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	1022	1050	1078
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+.9	+1.0
Fixed Charge Cov. (%)	278	285	259

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.0%	--	2.5%
"Cash Flow"	4.5%	3.5%	4.5%
Earnings	8.0%	5.5%	6.0%
Dividends	4.0%	6.0%	5.5%
Book Value	4.0%	6.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	597.8	333.9	325.5	477.7	1734.9
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	*410*	*420*	*526.4*	*2180*
2023	*825*	*415*	*425*	*560*	*2225*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.73	.24	.44	1.13	3.53
2020	1.59	.33	.58	1.23	3.73
2021	1.54	.40	.70	1.11	3.74
2022	1.82	*.40*	*.60*	*1.28*	*4.10*
2023	*1.80*	*.45*	*.70*	*1.35*	*4.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.475	.475	.475	.505	1.93
2019	.505	.505	.505	.535	2.05
2020	.535	.535	.535	.565	2.17
2021	.565	.565	.565	.595	2.29
2022	.595	.595			

BUSINESS: Black Hills Corporation is a holding company for Black Hills Energy, which serves 218,000 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, 31%; commercial, 34%; industrial, 19%; other, 16%. Generating sources: coal, 34%; gas, 25%; wind, 11%; purchased, 30%. Fuel costs: 38% of revs. '21 deprec. rate: 3.1%. Has 2,900 employees. Chairman: David R. Emery. President & CEO: Linn Evans. Inc.: SD. Address: 7001 Mount Rushmore Rd., P.O. Box 1400, Rapid City, SD 57709-1400. Tel.: 605-721-1700. Internet: www.blackhillscorp.com.

Black Hills Corporation is poised for an earnings-per-share gain in the vicinity of 10% this year. The South Dakota utility is benefiting from rate relief that was signed off last year. Add to this, via riders, which are surcharges on customer's bills, a significant amount of its capital spending can be recouped. Customer growth has also been a boon too, as the areas that Black Hills serves are seeing an influx of people. Of course, there are some headwinds like higher maintenance and cloud-computing licensing costs. Also, equity issuances that took place in 2021, and an additional $100 million-plus set for this year, have shares outstanding on an incline. Still, the positives have been outweighing the negatives, and we think share net should clock in around $4.10 when all is said and done.

The company has inked its first agreement for service under its Blockchain Interruptible Service Tariff. Cheyenne Light, Fuel, and Power Company, BKH's Wyoming electric utility doing business as Black Hills Energy, signed a five-year pact to deliver up to 45 megawatts of service (with an option to get to 75 megawatts) to a crypto mining facility. The customer should be up and operating by the fourth quarter of this year. The Tariff, approved in 2019, was developed to attract new electric loads tied to blockchain usage and generate local benefits like property and sales tax for Wyoming.

For 2023, we look for earnings growth to be more in line with the company's in-house goal of 5% to 7% per annum. Rider revenues and continued rate relief will be in play. Too, an Arkansas gas rate review should be resolved by the end of 2022, with expected higher rates planned for 2023. On top of this, ongoing recovery from Winter Storm Uri remains in full swing. Approvals in Colorado and Kansas are in hand, while we await resolution on the Arkansas and Wyoming fronts. In sum, we think share net can increase by about 5% year over year, to $4.30.

This neutrally ranked selection (up a notch from our April review) has a dividend yield in line with the average utility. Regardless, total return potential for the coming 18 months and the 3- to 5-year period are not exciting.

Erik M. Manning *July 22, 2022*

(A) Dil. EPS. Excl. nonrec. gains (losses): '08, ($1.55); '09, (28¢); '10, 10¢; '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¢). '19 & '21 EPS don't sum due to rounding. Next egs. due August 3rd. (B) Div'ds pd. early Mar., Jun., Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '21: $28.20/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	45
Earnings Predictability	90

CENTERPOINT EN'RGY NYSE-CNP

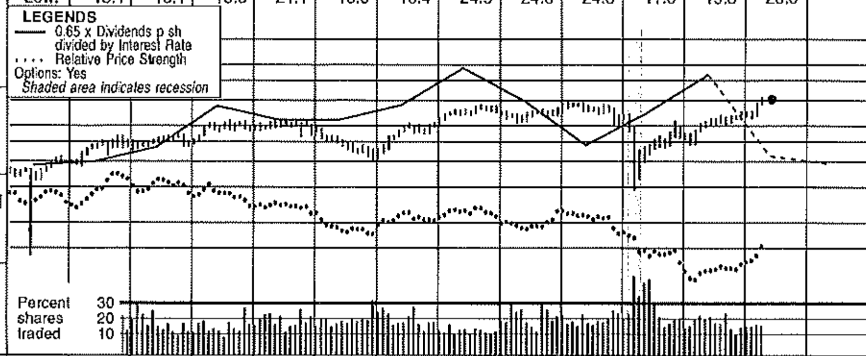
RECENT PRICE 32.42 | P/E RATIO 23.2 (Trailing: 30.9; Median: 19.0) | RELATIVE P/E RATIO 1.39 | DIV'D YLD 2.3% | VALUE LINE

TIMELINESS 3 Raised 3/4/22
SAFETY 3 Lowered 12/18/15
TECHNICAL 2 Raised 5/27/22
BETA 1.15 (1.00 = Market)

High:	21.5	21.8	25.7	25.8	23.7	25.0	30.5	29.6	31.4	27.5	28.4	33.0
Low:	15.1	18.1	19.3	21.1	16.0	16.4	24.5	24.8	24.3	11.6	19.3	26.0

Target Price Range 2025 | 2026 | 2027

LEGENDS
— 0.65 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)
$24-$39	$32 (-5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+10%)	5%
Low	25	(-25%)	-3%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	244	310	295
to Sell	208	192	251
Hld's(000)	573708	573456	566118

Percent shares traded 30 20 10

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	28.7	-7.2
3 yr.	8.2	37.2
5 yr.	27.2	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
29.71	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	*14.30*	*14.90*	Revenues per sh	*16.75*
3.47	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*	*3.85*	"Cash Flow" per sh	*4.50*
1.33	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	*1.40*	*1.50*	Earnings per sh A	*1.80*
.60	.68	.73	.76	.78	.79	.81	.83	.95	.99	1.03	1.35	1.12	.86	.90	.66	*.71*	*.77*	Div'd Decl'd per sh B ■	*.95*
3.21	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	*6.10*	*7.45*	Cap'l Spending per sh	*7.25*
4.96	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	*14.75*	*15.50*	Book Value per sh C	*18.00*
313.65	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	*630.00*	*631.00*	Common Shs Outst'g D	*634.00*
10.3	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	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.56	.80	.68	.79	.88	.92	.94	1.05	.89	.91	1.15	.90	2.00	1.04	.82	1.39	*Value Line*		Relative P/E Ratio	*.90*
4.4%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $13879 mill. **Due in 5 Yrs** $7844 mill.
LT Debt $12106 mill. **LT Interest** $375 mill.
Incl. $317 mill. securitized transition & system restoration bonds.
(LT interest earned: 2.4x)
Leases, Uncapitalized Annual rentals $6 mill.
Pension Assets-12/21 $2072 mill. Oblig $2298 mill.
Pfd Stock $790 mill. **Pfd Div'd** $49 mill.
800,000 shs. 6.125%, cumulative, with liquidation value of $1000.
Common Stock 629,448,787 shs. as of 4/20/22
MARKET CAP: $20 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
7452.0	8106.0	9226.0	7386.0	7528.0	9614.0	10589	12301	7418.0	8352.0	*9000*	*9400*	Revenues ($mill)	*10600*
581.0	536.0	611.0	465.0	432.0	679.0	368.0	871.0	863.0	668.0	*950*	*1000*	Net Profit ($mill)	*1180*
33.4%	31.4%	31.0%	35.1%	37.0%	36.1%	28.4%	14.9%	13.4%	14.1%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
2.6%	3.5%	4.1%	4.7%	3.5%	2.9%	5.4%	6.7%	6.0%	9.3%	*6.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
66.0%	64.4%	63.8%	69.5%	68.5%	63.6%	51.9%	63.0%	58.0%	62.3%	*62.0%*	*59.0%*	Long-Term Debt Ratio	*60.0%*
34.0%	35.6%	36.2%	30.5%	31.5%	36.4%	37.5%	29.1%	29.9%	34.5%	*35.0%*	*38.0%*	Common Equity Ratio	*37.5%*
12658	12146	12557	11362	10992	12883	16740	22603	19869	24973	*26525*	*25725*	Total Capital ($mill)	*30400*
13597	9593.0	10502	11537	12307	13057	14044	20945	22362	23484	*25925*	*29150*	Net Plant ($mill)	*35700*
6.8%	6.3%	6.7%	6.1%	5.8%	6.8%	3.4%	5.1%	5.6%	3.8%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.0%*
13.5%	12.4%	13.4%	13.4%	12.5%	14.5%	4.6%	10.4%	10.3%	7.1%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
13.5%	12.4%	13.4%	13.4%	12.5%	14.5%	5.3%	11.5%	11.6%	6.7%	*9.5%*	*10.0%*	Return on Com Equity E	*10.0%*
5.5%	4.2%	4.5%	1.1%	NMF	4.7%	NMF	2.7%	5.0%	2.2%	*5.0%*	*5.0%*	Retained to Com Eq	*4.5%*
60%	66%	67%	92%	103%	68%	NMF	80%	66%	72%	*52%*	*53%*	All Div'ds to Net Prof	*54%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+6.7	+1.8	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.)	+7.9	+2.5	NA
Fixed Charge Cov. (%)	152	135	181

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.0%	-2.0%	-.5%
"Cash Flow"	1.0%	-.5%	4.0%
Earnings	1.0%	1.0%	6.5%
Dividends	.5%	-4.0%	2.5%
Book Value	4.5%	7.0%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	3531	2798	2742	3230	12301
2020	2167	1575	1622	2054	7418
2021	2547	1742	1749	2314	8352
2022	2763	*1837*	*1900*	*2500*	*9000*
2023	*2900*	*1900*	*2000*	*2600*	*9400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.28	.33	.47	.41	1.49
2020	.56	.17	.29	.27	1.29
2021	.41	.29	.21	.03	.94
2022	.52	*.33*	*.30*	*.25*	*1.40*
2023	*.50*	*.35*	*.35*	*.30*	*1.50*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.2775	.2775	.2775	.2775	1.11
2019	.2875	.2875	.2875	.2875	1.15
2020	.29	.15	.15	.15	.74
2021	.16	.16	.16	.17	.65
2022	.17	.17			

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 150,000 customers, and gas utilities with 4.2 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: 28% of revenues. '21 depreciation rate: 3.9%. Has 8,900 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 has completed its exit from its midstream natural gas investment. The sale of the company's units in Energy Transfer, at a 20% premium to the value when Energy Transfer acquired Enable Midstream Partners last year, raised $1.3 billion after taxes. This is being used for debt reduction and capital spending. The net effect of the sale boosted earnings by $0.05 a share in the first quarter, which we *included* in our presentation because it was immaterial.

The company also completed the sales of two of its gas utilities in the first quarter of 2022. The sales of the utilities in Arkansas and Oklahoma raised $1.6 billion (including about $400 million to compensate for extraordinary gas costs that were incurred during a cold spell in February of 2021). The valuation was attractive, at 2.5 times rate base. CenterPoint recorded a gain of $0.30 a share on the sales, which we *excluded* from our earnings presentation as a nonrecurring item. The divestitures are expected to reduce share net by just $0.02 this year.

The proceeds from these asset sales are being used for debt reduction and capital spending. CenterPoint expects it will not need to issue common equity through 2030, although the share count might well rise slightly due to stock issued for options and various other plans.

Earnings should improve significantly in 2022. The comparison is easy, as CenterPoint incurred some unusual expenses in 2021 in what was a year of transition. We expect further growth in 2023. Rate relief and increased volume are factors contributing to this.

Some regulatory matters are pending. In Minnesota, CenterPoint reached a settlement calling for a $48.5 million gas rate increase, based on a 9.39% return on equity. An order from the state commission is expected in the third quarter. In Texas, Houston Electric is seeking $146 million, and its gas utilities are requesting $34 million under annual cost-recovery mechanisms.

We think more-attractive selections are available elsewhere. The stock's dividend yield is about a percentage point below the utility average, and prospects don't stand out for the 2025-2027 period.

Paul E. Debbas, CFA *June 10, 2022*

(A) Dil. EPS. Excl. nonrecur. gains (losses): '11, $1.89; '12, (38¢); '13, (52¢); '15, ($2.69); '17, $2.56; '20, ($2.74); '22, 30¢; gain (loss) on disc. ops.: '20, (34¢); '21, $1.34. Next earnings 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 '21: $10.52/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., '21: 7.9%. Regulatory Climate: TX, Avg.; IN, Above Avg.

Company's Financial Strength	B+
Stock's Price Stability	70
Price Growth Persistence	25
Earnings Predictability	50

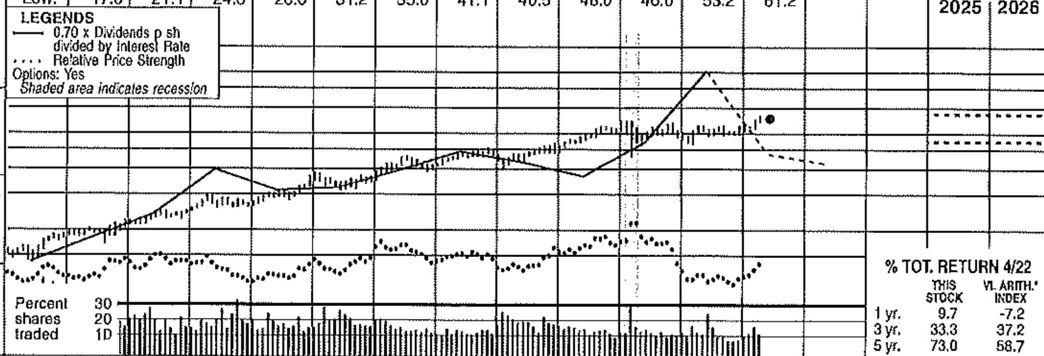
CMS ENERGY CORP. NYSE-CMS

RECENT PRICE 71.47 | P/E RATIO 24.6 (Trailing: 26.6, Median: 20.0) | RELATIVE P/E RATIO 1.47 | DIV'D YLD 2.6% | VALUE LINE

TIMELINESS 3 Raised 3/25/22
SAFETY 2 Raised 3/21/14
TECHNICAL 3 Lowered 6/3/22
BETA .75 (1.00 = Market)

High:	22.4	25.0	30.0	36.9	38.7	46.3	50.8	53.8	65.3	69.2	65.8	73.8
Low:	17.0	21.1	24.6	26.0	31.2	35.0	41.1	40.5	46.0	46.0	53.2	61.2

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range

Low-High: $59-$90 | Midpoint (% to Mid): $75 (5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+5%)	4%
Low	55	(-25%)	-3%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	261	249	329
to Sell	244	277	222
Hld's(000)	270396	270027	272596

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.7	-7.2
3 yr.	33.3	37.2
5 yr.	73.0	56.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
30.57	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	*28.30*	*28.95*	Revenues per sh	*30.75*
3.22	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	*7.00*	*7.45*	"Cash Flow" per sh	*8.75*
.64	.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	*2.90*	*3.10*	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*	*1.94*	Div'd Decl'd per sh B ■	*2.30*
3.01	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	*8.95*	*10.00*	Cap'l Spending per sh	*9.75*
10.03	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	*23.20*	*24.35*	Book Value per sh C	*29.25*
222.78	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	*290.00*	*290.00*	Common Shs Outst'g D	*300.00*
22.2	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	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
1.20	1.42	.66	.91	.80	.85	.96	.92	.91	.92	1.10	1.07	1.10	1.29	1.20	1.26	*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%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $12473 mill. **Due in 5 Yrs** $2324 mill.
LT Debt $12091 mill. **LT Interest** $439 mill.
Incl. $46 mill. finance leases.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $5 mill.
Pension Assets-12/21 $3599 mill.
Oblig $3070 mill.
Pfd Stock $261 mill. **Pfd Div'd** $11 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 290,129,103 shs.
as of 4/11/22
MARKET CAP: $21 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
6312.0	6566.0	7179.0	6456.0	6399.0	6583.0	6873.0	6845.0	6680.0	7329.0	*8200*	*8400*	Revenues ($mill)	*9200*
413.0	454.0	479.0	525.0	553.0	610.0	659.0	682.0	757.0	751.0	*850*	*915*	Net Profit ($mill)	*1140*
39.4%	39.9%	34.3%	34.0%	33.1%	31.2%	14.9%	17.7%	15.0%	11.5%	*11.0%*	*11.0%*	Income Tax Rate	*11.0%*
2.9%	2.0%	2.3%	2.7%	3.1%	1.1%	1.4%	2.1%	1.1%	1.5%	*1.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
67.9%	67.5%	68.7%	68.3%	67.1%	67.3%	69.0%	70.4%	71.2%	64.5%	*63.5%*	*63.5%*	Long-Term Debt Ratio	*61.0%*
31.6%	32.2%	31.0%	31.4%	32.6%	32.4%	30.7%	29.4%	28.6%	34.2%	*35.0%*	*35.5%*	Common Equity Ratio	*38.0%*
10101	10730	11846	12534	13040	13692	15476	17082	19223	18760	*19200*	*19950*	Total Capital ($mill)	*23300*
11551	12246	13412	14705	15715	16761	18126	18926	21039	22352	*23775*	*25400*	Net Plant ($mill)	*29900*
5.9%	6.0%	5.7%	5.7%	5.8%	5.9%	5.6%	5.3%	5.2%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
12.8%	13.0%	12.9%	13.2%	12.9%	13.6%	13.8%	13.5%	13.7%	11.3%	*12.0%*	*12.5%*	Return on Shr. Equity	*12.5%*
12.9%	13.1%	13.0%	13.3%	13.0%	13.7%	13.8%	13.6%	13.7%	11.6%	*12.5%*	*13.0%*	Return on Com Equity E	*13.0%*
5.0%	5.2%	5.0%	5.2%	4.8%	5.2%	5.3%	4.9%	5.3%	3.8%	*4.5%*	*5.0%*	Retained to Com Eq	*5.0%*
61%	60%	62%	61%	63%	62%	62%	64%	62%	68%	*64%*	*63%*	All Div'ds to Net Prof	*61%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-3.7	-3.1	+2.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.94	8.14	8.46
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	8039	8215	7951
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+1.0	*+1*
Fixed Charge Cov. (%)	235	240	223

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.0%	--	*4.0%*
"Cash Flow"	5.5%	6.5%	*6.0%*
Earnings	7.5%	6.5%	*6.5%*
Dividends	9.5%	7.0%	*6.0%*
Book Value	5.5%	6.5%	*7.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2059	1445	1546	1795	6845
2020	1864	1443	1575	1798	6680
2021	2013	1558	1725	2033	7329
2022	2374	*1700*	*1900*	*2226*	*8200*
2023	*2400*	*1750*	*1950*	*2300*	*8400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.75	.33	.73	.58	2.39
2020	.85	.48	.76	.55	2.64
2021	1.09	.55	.54	.40	2.58
2022	1.20	*.60*	*.65*	*.45*	*2.90*
2023	*1.25*	*.65*	*.70*	*.50*	*3.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec. 31	Full Year
2018	.3575	.3575	.3575	.3575	1.43
2019	.3825	.3825	.3825	.3825	1.53
2020	.4075	.4075	.4075	.4075	1.63
2021	.435	.435	.435	.435	1.74
2022	.46	.46			

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 1,234 megawatts of nonregulated generating capacity. Sold EnerBank in '21. Electric revenue breakdown: residential, 48%; commercial, 32%; industrial, 13%; other, 7%. Generating sources: coal, 31%; gas, 16%; renewables, 6%; purchased, 47%. Fuel costs: 42% of revenues. '21 reported deprec. rates: 3.9% electric, 2.9% gas, 9.4% other. Has 8,500 full-time employees. Chairman: John G. Russell. President & CEO: Garrick Rochow. Inc.: Michigan. Address: One Energy Plaza, Jackson, Michigan 49201. Tel.: 517-788-0550. Internet: www.cmsenergy.com.

CMS Energy's utility subsidiary has electric and gas rate cases pending. Consumers Energy is seeking a gas rate increase of $233 million, based on a 10.25% return on equity and a 52% common-equity ratio. The staff of the Michigan Public Service Commission (MPSC) recommended a hike of $172 million, based on a 9.6% ROE and a 51.05% common-equity ratio. An order from the MPSC is due by October 3rd. The utility filed for an electric tariff increase of $272 million, based on a 10.25% ROE and a 51.5% common-equity ratio. The MPSC's ruling is expected in the first quarter of 2023. Consumers Energy needs frequent rate relief because it has a large electric and gas system with a lot of aged equipment that needs to be replaced. In recent years, Michigan regulation has usually been constructive, but the utility's last electric rate order ($54 million at the start of 2022) was disappointing.

Earnings will likely improve substantially in 2022. The comparison witb the 2021 tally is easy. The company recorded a charge of $0.07 a share for a fleet impairment in the fourth quarter of 2021. Rate relief is another factor; the aforementioned electric increase, though disappointing, will help. Consumers Energy will also get a quarter of the gas rate increase. Management is controlling expenses effectively, even in the face of inflation pressures. Our estimate of $2.90 a share is slightly above CMS Energy's guidance of $2.85-$2.89, which we consider conservative.

We estimate 7% earnings growth in 2023. The company will benefit from a full year's effect of gas rate relief and a partial year of the electric hike. CMS Energy's goal for annual earnings growth is 6%-8%.

Consumers Energy reached a settlement on its integrated resource plan. The company had hoped to convert a nonregulated asset to a regulated one. Instead, it will issue a request for proposals for 700 megawatts of capacity. The MPSC must still rule on the settlement. Its order is expected in late June.

This stock is priced expensively. The dividend yield is below the utility average. Witb the recent quotation well within our 2025-2027 Target Price Range, total return potential over that time frame is low.

Paul E. Debbas, CFA *June 10, 2022*

(A) Diluted EPS. Excl. nonrec. gains (losses): '06, ($1.08); '07, ($1.26); '09, (7¢); '10, 3¢; '11, 12¢; '12, (14¢); '17, (53¢); gains (losses) on disc. ops.: '06, 3¢; '07, (40¢); '09, 8¢; '10, (8¢); '11, 1¢; '12, 3¢; '21, $2.08; '22, 1¢. Next earnings report due early Aug. (B) Div'ds historically paid late Feb., May, Aug., & Nov. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '21: $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	B++
Stock's Price Stability	95
Price Growth Persistence	65
Earnings Predictability	95

CON. EDISON NYSE-ED

RECENT PRICE 92.01 | P/E RATIO 20.0 (Trailing: 19.4; Median: 17.0) | RELATIVE P/E RATIO 1.20 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 3 Raised 1/7/22
SAFETY 1 New 7/27/90
TECHNICAL 2 Raised 5/13/22
BETA .75 (1.00 = Market)

18-Month Target Price Range
Low-High: $62-$96 | Midpoint (% to Mid): $79 (-15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+15%)	7%
Low	85	(-10%)	2%

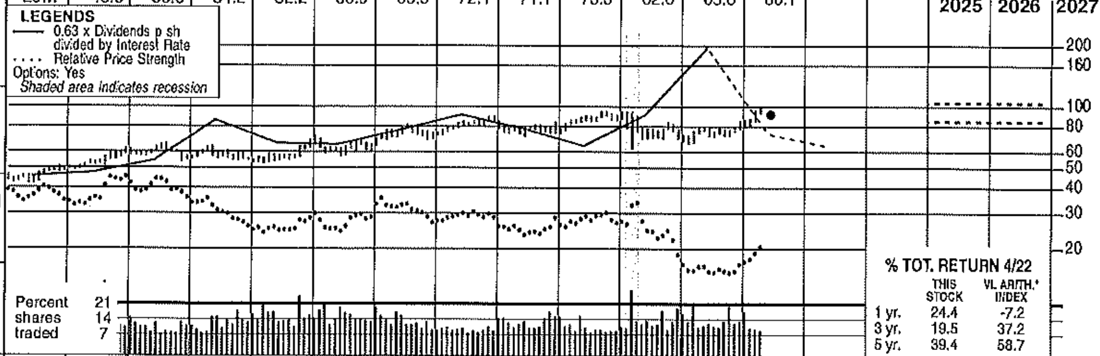
Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	471	446	487
to Sell	348	338	367
Hld's(000)	216551	219342	224882

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	62.7	66.0	64.0	68.9	72.3	81.9	89.7	84.9	95.0	95.1	85.6
Low:	48.6	53.6	54.2	52.2	56.9	63.5	72.1	71.1	73.3	62.0	65.6

	2022
High:	99.2
Low:	80.1

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



% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	24.4	-7.2
3 yr.	19.5	37.2
5 yr.	39.4	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
47.14	48.23	49.62	46.36	45.69	44.17	41.62	42.27	44.11	42.85	39.59	38.62	38.44	37.80	35.78	38.63	*39.75*	*40.55*	Revenues per sh	*43.50*
5.28	5.77	5.99	5.86	6.24	6.61	7.15	7.45	7.30	7.93	7.89	8.41	8.92	9.10	9.48	10.42	*10.40*	*10.80*	"Cash Flow" per sh	*12.25*
2.95	3.48	3.36	3.14	3.47	3.57	3.86	3.93	3.62	4.05	3.94	4.10	4.55	4.08	3.94	4.74	*4.60*	*4.75*	Earnings per sh A	*5.50*
2.30	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*	Div'd Decl'd per sh B ■	*3.50*
7.17	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	*12.60*	*14.75*	Cap'l Spending per sh	*14.50*
31.09	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	*58.90*	*60.85*	Book Value per sh C	*67.25*
257.46	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	*365.00*	*370.00*	Common Shs Outst'g D	*380.00*
15.5	13.8	12.3	12.5	13.3	15.1	15.4	14.7	15.9	15.6	18.8	19.8	17.1	21.1	20.1	15.9	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.84	.73	.74	.83	.85	.95	.98	.83	.84	.79	.99	1.00	.92	1.12	1.03	.86	*Value Line*		Relative P/E Ratio	*.95*
5.0%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $24532 mill. Due in 5 Yrs $3994 mill.
LT Debt $22604 mill. LT Interest $904 mill.
(LT interest earned: 2.9x)

Leases, Uncapitalized Annual rentals $81 mill.

Pension Assets-12/21 $18504 mill. Oblig $17357 mill.

Pfd Stock None

Common Stock 354,090,402 shs. as of 1/31/22

MARKET CAP: $33 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
12188	12381	12919	12554	12075	12033	12337	12574	12246	13676	*14500*	*15000*	Revenues ($mill)	*16500*
1141.0	1157.0	1066.0	1193.0	1189.0	1266.0	1424.0	1343.0	1324.0	1655.0	*1665*	*1755*	Net Profit ($mill)	*2060*
34.5%	31.8%	34.0%	33.6%	35.3%	36.6%	20.1%	17.1%	12.0%	17.7%	*18.0%*	*18.0%*	Income Tax Rate	*18.0%*
.5%	.5%	.3%	.7%	1.3%	1.5%	1.5%	2.0%	2.3%	1.9%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
45.9%	46.1%	48.0%	47.9%	50.8%	48.9%	51.1%	50.7%	52.0%	53.0%	*51.5%*	*51.0%*	Long-Term Debt Ratio	*50.5%*
54.1%	53.9%	52.0%	52.1%	49.2%	51.1%	48.9%	49.3%	48.0%	47.0%	*48.5%*	*49.0%*	Common Equity Ratio	*49.5%*
21933	22735	24207	25058	29033	30149	34221	36549	39229	42641	*44225*	*46050*	Total Capital ($mill)	*51600*
26939	28436	29827	32209	35216	37600	41749	43889	46555	48596	*51075*	*54300*	Net Plant ($mill)	*63500*
6.5%	6.4%	5.6%	6.0%	5.3%	5.4%	5.3%	4.9%	4.5%	5.0%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
9.6%	9.4%	8.5%	9.1%	8.3%	8.2%	8.5%	7.5%	7.0%	8.3%	*7.5%*	*8.0%*	Return on Shr. Equity	*8.0%*
9.6%	9.4%	8.5%	9.1%	8.3%	8.2%	8.5%	7.5%	7.0%	8.3%	*7.5%*	*8.0%*	Return on Com Equity E	*8.0%*
3.6%	3.6%	2.6%	3.5%	3.0%	3.0%	3.5%	2.3%	1.9%	3.1%	*2.5%*	*2.5%*	Retained to Com Eq	*3.0%*
62%	62%	69%	61%	64%	63%	59%	69%	74%	62%	*68%*	*68%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.9	-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)	13835	13170	13517
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	267	257	284

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.0%	-2.5%	*2.5%*
"Cash Flow"	4.5%	4.5%	*4.0%*
Earnings	2.5%	2.0%	*4.5%*
Dividends	2.5%	3.0%	*2.5%*
Book Value	4.0%	4.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	3514	2744	3365	2951	12574
2020	3234	2719	3333	2960	12246
2021	3677	2971	3613	3415	13676
2022	*3900*	*3200*	*3850*	*3550*	*14500*
2023	*4050*	*3300*	*4000*	*3650*	*15000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.31	.46	1.42	.88	4.08
2020	1.12	.57	1.47	.78	3.94
2021	1.58	.56	1.52	1.09	4.74
2022	*1.50*	*.60*	*1.60*	*.90*	*4.60*
2023	*1.55*	*.60*	*1.65*	*.95*	*4.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.715	.715	.715	.715	2.86
2019	.74	.74	.74	.74	2.96
2020	.765	.765	.765	.765	3.06
2021	.775	.775	.775	.775	3.10
2022	.79				

BUSINESS: Consolidated Edison, Inc. is a holding company for Consolidated Edison Company of New York, Inc. (CECONY), which sells electricity, gas, and steam in most of New York City and Westchester County. Also owns Orange and Rockland Utilities (O&R), which operates in New York and New Jersey. Has 3.7 mill. electric, 1.2 mill. gas customers. Pursues competitive energy opportunities through three wholly owned subsidiaries. Entered into midstream gas joint venture 6/16; sold it 7/21. Purchases most of its power. Fuel costs: 20% of revenues. '21 reported deprec. rates: 3.1%-3.5%. Has 13,900 employees. Chairman, President & CEO: Timothy Cawley. Inc.: NY. Address: 4 Irving Place, New York, NY 10003. Tel.: 212-460-4600. Internet: www.conedison.com.

Consolidated Edison's primary utility subsidiary has a major rate case pending. Consolidated Edison Company of New York filed for electric increases of $1.2 billion in 2023, $853 million in 2024, and $608 million in 2025. The utility requested gas tariff hikes of $503 million in 2023, $234 million in 2024, and $218 million in 2025. The application is based on a 10% return on equity and a 50% common-equity ratio, up from the currently allowed 8.8% and 48%, respectively. Numerous factors are driving the rate case, including the need to place new infrastructure expenditures in the rate base and to recover higher property taxes. Asking for price increases is always challenging, but even more so now given the inflationary environment. The utility will attempt to settle the case. An order is expected by yearend.

The New York State Department of Public Service approved a settlement for Orange and Rockland. The order was retroactive to the start of 2022. Electric rates were raised $4.9 million in 2022, $16.2 million in 2023, and $23.1 million in 2024. Gas tariffs were boosted $0.7 million in 2022, $7.4 million in 2023, and $9.9 million in 2024. This was based on a 9.2% ROE (up from 9.0% previously) and a 48% common-equity ratio.

Our 2022 share-earnings estimate is at the upper end of ConEd's guidance of $4.40-$4.60. The company excludes an expected $0.11 a share of income from hypothetical liquidation at book value accounting for tax-equity investors in certain renewable-energy projects, but we include this because it is an ongoing part of ConEd's results. This amounted to $0.29 last year, which is one reason why we estimate lower profits than in 2021. In 2023, rate relief ought to boost the bottom line. Note that we will also include any mark-to-market accounting gains or losses. These, too, are an ongoing part of ConEd's results. Sources of uncertainty are inflation, supply-chain problems, and potentially higher tariffs for solar panels for the renewable-energy segment.

This stock's dividend yield is about average for a utility. However, total return potential is negative for the next 18 months and unspectacular for the 3- to 5-year period.

Paul E. Debbas, CFA *May 13, 2022*

(A) Diluted EPS. Excl. nonrec. gains (losses): '13, (32¢); '14, 9¢; '16, 15¢; '17, 84¢; '18, (13¢); '20, (66¢); '21, (43¢); gain on disc. operations: '08, $1.01. '19, '21 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds historically paid in mid-Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '21: $15.17/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%; earned on avg. com. eq., '21: 8.4%. Regulatory Climate: Below Average.

Company's Financial Strength	A+
Stock's Price Stability	90
Price Growth Persistence	35
Earnings Predictability	100

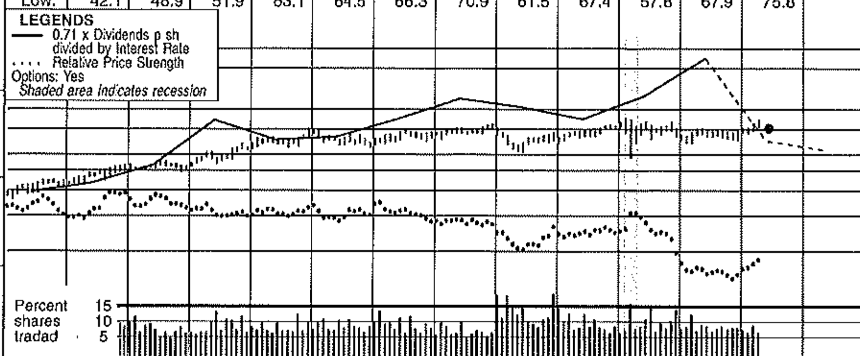
DOMINION ENERGY NYSE-D

RECENT PRICE 81.05 | P/E RATIO 20.0 (Trailing: 25.4 / Median: 22.0) | RELATIVE P/E RATIO 1.20 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 4 Lowered 2/5/21
SAFETY 2 Raised 9/11/98
TECHNICAL 2 Raised 4/29/22
BETA .80 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	53.6	55.6	68.0	80.9	79.9	79.0	85.3	81.7	83.9	90.9	81.1	88.8
Low:	42.1	48.9	51.9	63.1	64.5	66.3	70.9	61.5	67.4	57.8	67.9	75.8

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$77-$110 $94 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+30%)	10%
Low	80	(Nil)	4%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	634	613	680
to Sell	635	616	612
Hld's(000)	536264	546775	558255

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.9	-7.2
3 yr.	17.4	37.2
5 yr.	26.8	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB, LLC	25-27
23.61	27.17	27.93	25.24	26.17	25.24	22.73	22.56	21.25	19.59	18.70	19.53	19.63	19.78	17.59	17.23	*17.95*	*18.30*	Revenues per sh	*19.25*
4.91	5.08	5.07	4.82	5.11	5.04	5.24	5.47	5.71	5.98	6.33	6.90	6.48	5.73	5.49	6.68	*7.60*	*8.10*	"Cash Flow" per sh	*9.50*
2.40	2.13	3.04	2.64	2.89	2.76	2.75	3.09	3.05	3.20	3.44	3.53	3.25	2.19	1.82	3.19	*4.05*	*4.35*	Earnings per sh A	*5.25*
1.38	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*	*2.83*	Div'd Decl'd per sh B ■	*3.40*
5.81	6.89	6.09	6.40	5.89	6.41	7.20	7.06	9.13	9.35	9.69	8.54	6.25	5.94	7.47	7.35	*10.30*	*12.25*	Cap'l Spending per sh	*8.75*
18.50	16.31	17.28	18.58	20.66	20.09	18.34	20.02	19.74	21.24	23.26	26.59	29.53	35.33	29.46	31.50	*34.35*	*36.20*	Book Value per sh C	*43.00*
698.00	576.80	583.20	599.40	580.80	569.70	576.10	581.50	585.30	596.30	627.80	644.60	680.90	838.00	805.60	810.40	*835.00*	*842.00*	Common Shs Outst'g D	*870.00*
16.0	20.6	13.8	12.7	14.3	17.3	18.9	19.2	23.0	22.1	21.3	22.2	21.8	NMF	NMF	23.6	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
.86	1.09	.83	.85	.91	1.09	1.20	1.08	1.21	1.11	1.12	1.12	1.18	NMF	NMF	1.28	*Value Line*		Relative P/E Ratio	*.95*
3.6%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*
						13093	13120	12436	11683	11737	12586	13366	16572	14172	13964	*15000*	*15400*	Revenues ($mill)	*16750*
						1594.0	1806.0	1793.0	1899.0	2123.0	2244.0	2130.0	1838.0	1648.0	2715.0	*3465*	*3760*	Net Profit ($mill)	*4715*
						36.2%	33.0%	28.1%	32.0%	22.8%	27.2%	17.7%	21.8%	5.9%	13.7%	*17.0%*	*17.0%*	Income Tax Rate	*17.0%*
						5.7%	3.7%	4.5%	5.3%	7.5%	10.5%	6.3%	4.8%	6.3%	4.3%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
						60.9%	61.9%	65.4%	65.1%	67.4%	64.4%	60.8%	51.4%	56.5%	56.4%	*56.5%*	*56.0%*	Long-Term Debt Ratio	*56.0%*
						38.2%	37.3%	34.6%	34.9%	32.6%	35.6%	39.2%	45.0%	39.5%	38.5%	*41.0%*	*41.5%*	Common Equity Ratio	*42.0%*
						27676	31229	33360	36280	44836	48090	51251	65818	60074	66344	*70050*	*73225*	Total Capital ($mill)	*88900*
						30773	32628	36270	41554	49964	53758	54560	69082	57848	59774	*65400*	*72575*	Net Plant ($mill)	*91200*
						7.5%	7.3%	6.6%	6.5%	6.0%	5.9%	5.5%	4.0%	3.9%	5.1%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
						14.7%	15.2%	15.5%	15.0%	14.5%	13.1%	10.6%	5.7%	6.3%	9.4%	*11.0%*	*11.5%*	Return on Shr. Equity	*12.0%*
						14.9%	15.4%	15.4%	15.0%	14.5%	13.1%	10.6%	6.2%	6.7%	10.4%	*11.5%*	*12.0%*	Return on Com Equity E	*12.5%*
						3.5%	4.2%	3.3%	2.9%	2.7%	1.8%	NMF	NMF	NMF	2.4%	*4.0%*	*4.5%*	Retained to Com Eq	*4.5%*
						77%	73%	79%	81%	81%	86%	103%	NMF	NMF	77%	*67%*	*66%*	All Div'ds to Net Prof	*64%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $40581 mill. **Due in 5 Yrs** $14043 mill.
LT Debt $37426 mill. **LT Interest** $1337 mill.
(LT interest earned: 3.1x)
Leases, Uncapitalized Annual rentals $50 mill.
Pension Assets-12/21 $10890 mill.
Oblig $11945 mill.
Pfd Stock $3393 mill. **Pfd Divd** $65 mill.
2 mill. shs. 1.75%, cum., conv. in 2022. 800,000 shs. 4.65%, cum., not redeem. before 12/15/24. 1 mill. shs. 4.35%, cum., with divd. rate reset every 5 yrs., not redeem. before 1/15/27.
Common Stock 810,463,489 shs. as of 2/11/22
MARKET CAP: $66 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% 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. (%)	166	128	188

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-3.5%	-1.5%	*1.0%*
"Cash Flow"	2.0%	- -	*8.0%*
Earnings	-1.5%	-6.0%	*14.0%*
Dividends	5.5%	4.5%	*1.0%*
Book Value	5.0%	8.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	3858	3970	4269	4475	16572
2020	3938	3106	3607	3521	14172
2021	3870	3038	3176	3880	13964
2022	*4200*	*3250*	*3350*	*4200*	*15000*
2023	*4300*	*3350*	*3450*	*4300*	*15400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	d.37	.13	1.23	1.22	2.19
2020	d.57	.90	.42	.98	1.82
2021	1.19	.30	.71	.99	3.19
2022	*1.10*	*.85*	*1.10*	*1.00*	*4.05*
2023	*1.25*	*.90*	*1.15*	*1.05*	*4.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.835	.835	.835	.035	3.34
2019	.9175	.9175	.9175	.9175	3.67
2020	.94	.94	.94	.63	3.45
2021	.63	.63	.63	.63	2.52
2022	.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, 40%; nuclear, 29%; coal, 9%; other, 5%; purchased, 17%. Fuel costs: 25% of revs. '21 reported deprec. rates: 1.8%-3.8%. Has 17,100 employees. Chairmen, President & 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.

Dominion Energy's earnings will likely advance significantly in 2022. The comparison is easy due to some unusual charges that the company incurred last year. Besides this, Virginia Power benefits from recovery of certain capital expenditures through riders (surcharges) on customers' bills. The company is seeing load growth in Virginia and South Carolina, too. Dominion will also benefit from a full year's effect of general rate hikes that were granted in 2021. In September, the company received an electric rate increase in South Carolina of $62 million, based on a 9.5% return on equity, and in November, its gas utility in North Carolina had its rates raised $29 million, based on a 9.6% ROE. Finally, a return to normal weather patterns would add a nickel to the bottom line. Our estimate is within the company's targeted range of $3.95-$4.25 a share.

We expect further growth in 2023. The key factors should be volume growth and revenues resulting from continued investment at Virginia Power. Dominion's goal is average annual dividend growth of 6.5%, and our estimate would exceed this range. However, investors should note that certain things, such as mark-to-market accounting items and unrealized gains or losses on the company's nuclear decommissioning trust funds, can affect the comparisons. We *include* these in our earnings presentation because they are a normal part of Dominion's quarterly results.

The company has agreed to sell its gas utility in West Virginia for $690 million. This is Dominion's smallest utility. The price is attractive, at 26 times 2021 earnings. The proceeds will be used for debt reduction. The transaction requires the approval of the West Virginia commission and is expected to close in late 2022.

Virginia Power is proposing an offshore wind project. This requires approval of the state regulators. The utility would add 2.6 gigawatts of capacity at a cost of $10 billion, and is scheduled for completion in late 2026. However, offshore wind entails construction risk.

The untimely stock has a dividend yield that is about equal to the industry average. Total return potential is below average for the next 18 months and the 3- to 5-year period.

Paul E. Debbas, CFA *May 13, 2022*

(A) Dil. egs. Excl. nonrec. gains (losses): '08, 12¢; '09, (47¢); '10, $2.18; '11, (7¢); '12, ($1.70); '14, (76¢); '17, $1.19; '18, 43¢; '19, (58¢); gain (losses) from disc. ops.: '10, (26¢); '12, (4¢); '13, (16¢); '20, ($2.39); '21, 79¢. '19, '20 EPS don't add due to chg. in shs. Next egs. due early Aug. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '21: $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%; earned on avg. com. eq., '21: 10.9%. Reg. Clim.: Avg.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	50

DTE ENERGY CO. NYSE-DTE

RECENT PRICE 134.30 | P/E RATIO 24.0 (Trailing: 30.0; Median: 18.0) | RELATIVE P/E RATIO 1.44 | DIV'D YLD 2.7% | VALUE LINE

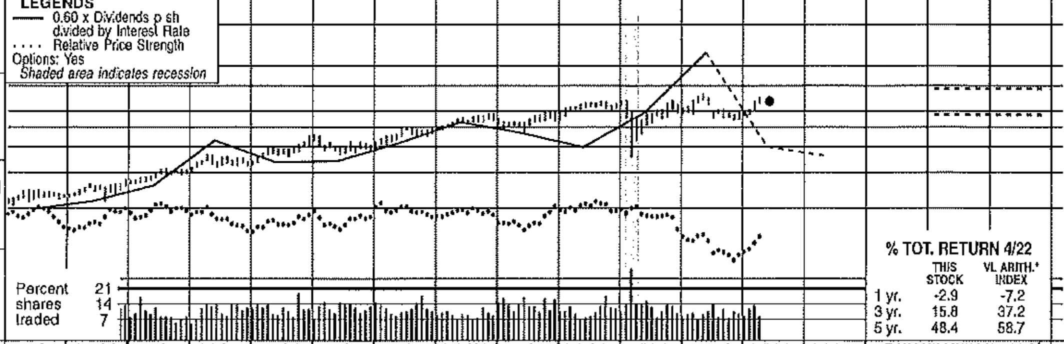
TIMELINESS 3 New 6/10/22
SAFETY 2 Raised 12/21/12
TECHNICAL 4 New 6/10/22
BETA .95 (1.00 = Market)

High:	55.3	62.6	73.3	90.8	92.3	100.4	116.7	121.0	134.4	135.7	145.4	140.2
Low:	43.2	52.5	60.3	64.8	73.2	78.0	96.6	94.3	107.3	71.2	108.2	113.8

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

18-Month Target Price Range
Low-High: $92-$150 · Midpoint (% to Mid): $121 (-10%)

Target Price Range 2025 | 2026 | 2027



2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	155	(+15%)	7%
Low	115	(-15%)	Nil

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	305	307	325
to Sell	270	272	274
Hld's(000)	141144	140364	143321

Percent shares traded: 21, 14, 7

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-2.9	-7.2
3 yr.	15.8	37.2
5 yr.	48.4	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
50.93	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	*87.80*	*90.25*	Revenues per sh	*93.25*
8.19	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*	*14.10*	"Cash Flow" per sh	*17.00*
2.45	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	*5.60*	*6.30*	Earnings per sh A	*7.50*
2.08	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	*3.60*	*3.84*	Div'd Decl'd per sh B ■	*4.65*
7.92	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	*18.05*	*17.05*	Cap'l Spending per sh	*18.50*
33.02	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	*50.65*	*53.25*	Book Value per sh C	*60.75*
177.14	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	*205.00*	*205.50*	Common Shs Outst'g D	*206.00*
17.4	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	Bold figures are		Avg Ann'l P/E Ratio	*17.5*
.94	.97	.89	.69	.78	.85	.95	1.01	.78	.91	1.00	.94	.94	1.06	.84	1.60	Value Line		Relative P/E Ratio	*.95*
4.9%	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%	estimates		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $18518 mill. Due in 5 Yrs $6481 mill.
LT Debt $15629 mill. LT Interest $514 mill.
Incl. $209 mill. securitization bonds. Incl. $19 mill. finance leases.
(LT interest earned: 2.3x)
Leases, Uncapitalized Annual rentals $16 mill.

Pension Assets-12/21 $5507 mill.
Oblig $5857 mill.

Pfd Stock None
Common Stock 193,739,166 shs.

MARKET CAP: $26 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
8791.0	9661.0	12301	10337	10630	12607	14212	12669	12177	14964	*18000*	*18550*	Revenues ($mill)	*19200*
666.0	661.0	905.0	796.0	868.0	1029.0	1120.0	1169.0	1368.0	796.0	*1090*	*1290*	Net Profit ($mill)	*1550*
29.8%	27.5%	28.5%	25.6%	24.5%	21.8%	8.1%	11.5%	10.9%	--	*5.0%*	*5.0%*	Income Tax Rate	*5.0%*
3.0%	3.5%	4.1%	4.3%	3.6%	3.5%	3.8%	3.3%	3.4%	4.9%	*4.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
48.8%	47.7%	50.0%	50.2%	55.6%	56.2%	54.2%	57.7%	60.5%	62.5%	*63.0%*	*61.5%*	Long-Term Debt Ratio	*61.0%*
51.2%	52.3%	50.0%	49.8%	44.4%	43.8%	45.8%	42.3%	39.5%	37.5%	*37.0%*	*38.5%*	Common Equity Ratio	*39.0%*
14387	15135	16670	17607	20280	21697	22371	27607	31426	23236	*28125*	*28350*	Total Capital ($mill)	*32200*
14684	15800	16620	18034	19730	20721	21650	25317	27969	26944	*29150*	*31050*	Net Plant ($mill)	*36600*
6.1%	5.7%	6.6%	5.7%	5.3%	5.9%	6.1%	5.3%	5.4%	4.7%	*5.0%*	*5.5%*	Return on Total Cap'l	*6.0%*
9.0%	8.3%	10.9%	9.1%	9.6%	10.8%	10.9%	10.0%	11.0%	9.1%	*10.5%*	*12.0%*	Return on Shr. Equity	*12.5%*
9.0%	8.3%	10.9%	9.1%	9.6%	10.8%	10.9%	10.0%	11.0%	9.1%	*10.5%*	*12.0%*	Return on Com Equity E	*12.5%*
3.5%	2.7%	5.2%	3.4%	3.7%	4.6%	4.9%	4.1%	4.9%	.1%	*3.5%*	*4.5%*	Retained to Com Eq	*4.5%*
61%	67%	52%	63%	61%	58%	55%	59%	56%	99%	*66%*	*61%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-3.9	-3.4	+2.1
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. (%)	260	268	233

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	3.0%	2.0%	*5.0%*
"Cash Flow"	3.5%	4.5%	*4.5%*
Earnings	5.0%	4.0%	*4.5%*
Dividends	6.0%	6.5%	*3.0%*
Book Value	3.5%	3.0%	*1.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	3514	2888	3119	3148	12669
2020	3022	2583	3284	3288	12177
2021	3581	3021	3715	4647	14964
2022	4577	*4000*	*4700*	*4763*	*18000*
2023	*4700*	*4150*	*4850*	*4850*	*18550*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2.19	.99	1.73	1.40	6.31
2020	1.76	1.44	2.46	1.42	7.08
2021	1.65	.60	.30	1.55	4.10
2022	2.03	*1.00*	*1.50*	*1.07*	*5.60*
2023	*2.45*	*1.10*	*1.60*	*1.15*	*6.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.8825	.8825	.8825	.8825	3.53
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			

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. '21 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 a general rate case pending. DTE Electric is seeking an increase of $388 million, based on a return on equity of 10.25% (up from the currently allowed 9.9%) and a common-equity ratio of 50% (unchanged). The staff of the Michigan Public Service Commission recommended a hike of $143 million, based on an ROE of 9.6% and the same common-equity ratio. An order is expected in November. This won't have much effect on the company's results this year, but will likely help boost earnings in 2023, as long as the utility receives reasonable regulatory treatment. Note that DTE Gas might file its next rate case in late 2022 or early 2023.

Earnings will likely wind up substantially higher in 2022, but the comparison isn't very meaningful. Last year was one of transition. DTE Energy spun off its midstream natural gas operations into a new company, DT Midstream (NYSE: DTM). The dividend was redneced, but when the DT Midstream dividends are included, shareholders are getting more dividend income than before the spinoff. In addition, the company took a pretax charge of $384 million for the early extinguishment of debt, which is why third-quarter earnings were well below normal.

The company's energy-trading business adds unpredictability to earnings. This operation books mark-to-market items each quarter, which even out over time. We *include* these in our earnings presentation even though DTE Energy excludes them from its definition of "operating" earnings. This hurt profits by $0.28 a share in the first quarter of 2022.

The share count will rise significantly by yearend. DTE Energy has $1.3 billion of equity units that will be converted to common stock in November. Little or no equity issuances are planned for 2023 and 2024.

The dividend yield of this stock is somewhat below the utility average. Although dividend growth potential (from the reduced level) is healthy, total return prospects to 2025-2027 are unexciting. The recent quotation is near the midpoint of our 3- to 5-year Target Price Range. Note that we have reinstated a Timeliness rank for tbis stock, which is 3 (Average).

Paul E. Debbas, CFA *June 10, 2022*

(A) Diluted EPS. Excl. nonrec. gains (loss): '07, $1.96; '08, 50¢; '11, 51¢; '15, (39¢); '17, 59¢; gains (losses) on disc. ops.: '06, (2¢); '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 reinv. plan avail. (C) Incl. intang. In '21: $29.17/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. 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	75

DUKE ENERGY NYSE-DUK

RECENT PRICE 108.70 | P/E RATIO 20.9 (Trailing: 22.0, Median: 19.0) | RELATIVE P/E RATIO 1.26 | DIV'D YLD 3.7%

VALUE LINE

TIMELINESS 4 Raised 3/25/22
SAFETY 2 New 6/1/07
TECHNICAL 3 Raised 4/29/22
BETA .85 (1.00 = Market)

18-Month Target Price Range
Low-High $94-$134 Midpoint (% to Mid) $114 (5%)

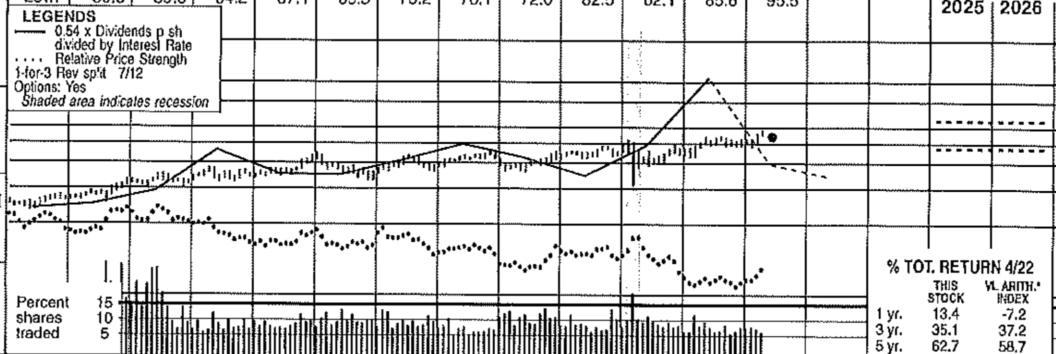
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	130	(+20%)	8%
Low	95	(-15%)	1%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	823	803	934
to Sell	623	615	627
Hld's(000)	483062	481215	484677

High:	66.4	71.1	75.5	87.3	90.0	87.8	91.8	91.4	97.4	103.8	108.4	116.3
Low:	50.6	59.6	64.2	67.1	65.5	70.2	76.1	72.0	82.5	62.1	85.6	95.5



% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.4	-7.2
3 yr.	35.1	37.2
5 yr.	62.7	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
25.32	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	*33.75*	*34.75*	Revenues per sh	*38.00*
7.86	8.11	7.34	7.58	8.49	8.68	6.80	8.56	9.11	9.40	9.20	10.01	10.49	12.13	10.89	12.30	*13.00*	*13.95*	"Cash Flow" per sh	*16.00*
2.76	3.60	3.03	3.39	4.02	4.14	3.71	3.98	4.13	4.10	3.71	4.22	4.13	5.07	3.92	4.93	*5.20*	*5.75*	Earnings per sh A	*6.50*
--	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*	Div'd Decl'd per sh B ■	*4.35*
8.07	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	*16.05*	*16.85*	Cap'l Spending per sh	*16.75*
62.30	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	*62.70*	*64.35*	Book Value per sh C	*70.00*
418.96	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*	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	19.4	17.7	22.4	20.1	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*17.0*
--	.85	1.04	.89	.81	.87	1.11	.98	.94	.92	1.12	1.00	1.05	.94	1.15	1.09	*estimates*		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%			Avg Ann'l Div'd Yield	*3.9%*

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
	19624	24598	23925	23459	22743	23565	24521	25079	23868	25097	*26000*	*26750*	Revenues ($mill)	*29200*
	2136.0	2813.0	2934.0	2854.0	2560.0	2963.0	2928.0	3755.0	2996.0	3901.0	*4100*	*4525*	Net Profit ($mill)	*5040*
	30.2%	32.6%	30.6%	32.2%	31.0%	30.4%	14.2%	12.7%	4.9%	5.1%	*10.0%*	*9.0%*	Income Tax Rate	*9.0%*
	22.3%	8.8%	7.2%	9.2%	11.7%	12.3%	13.0%	7.9%	8.9%	6.2%	*8.0%*	*7.0%*	AFUDC % to Net Profit	*7.0%*
	47.0%	48.0%	47.7%	48.6%	52.6%	54.0%	53.8%	54.0%	53.7%	55.1%	*56.5%*	*58.5%*	Long-Term Debt Ratio	*61.0%*
	52.9%	52.0%	52.3%	51.4%	47.4%	46.0%	46.2%	44.1%	44.4%	43.1%	*42.0%*	*40.0%*	Common Equity Ratio	*37.5%*
	77307	79482	78088	77222	86609	90774	94940	101807	103589	109744	*115150*	*124525*	Total Capital ($mill)	*144100*
	68558	69490	70046	75709	82520	86391	91694	102127	106782	111408	*117725*	*124375*	Net Plant ($mill)	*141100*
	3.6%	4.6%	4.8%	4.8%	4.0%	4.3%	4.2%	4.8%	3.9%	4.6%	*4.5%*	*4.5%*	Return on Total Cap'l	*4.5%*
	5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	6.7%	8.0%	6.2%	7.9%	*8.0%*	*9.0%*	Return on Shr. Equity	*9.0%*
	5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	6.7%	8.3%	6.3%	8.0%	*8.5%*	*9.0%*	Return on Com Equity E	*9.0%*
	.9%	1.5%	1.7%	1.5%	.6%	1.2%	1.0%	2.4%	.4%	1.4%	*2.0%*	*2.5%*	Retained to Com Eq	*3.0%*
	82%	78%	76%	79%	91%	83%	84%	71%	94%	83%	*77%*	*71%*	All Div'ds to Net Prof	*69%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $67139 mill. Due in 5 Yrs $19536 mill.
LT Debt $60448 mill. LT Interest $2206 mill.
Incl. $915 mill. finance leases.
(LT interest earned: 2.6x)
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 769,358,344 shs. as of 1/31/22
MARKET CAP: $84 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-.9	-2.3	+2.0
Avg. Indust. Use (MWH)	2934	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.)	+1.5	NA	NA
Fixed Charge Cov. (%)	233	183	209

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	-.5%	2.5%
"Cash Flow"	3.5%	5.0%	5.5%
Earnings	2.0%	3.0%	6.0%
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
2019	6163	5873	6940	6103	25079
2020	5949	5421	6721	5777	23868
2021	6150	5758	6951	6238	25097
2022	*6450*	*5950*	*7250*	*6350*	*26000*
2023	*6650*	*6100*	*7450*	*6550*	*26750*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.24	1.12	1.82	.89	5.07
2020	1.24	1.08	1.74	d.13	3.92
2021	1.25	.96	1.79	.93	4.93
2022	*1.10*	*1.15*	*1.90*	*1.05*	*5.20*
2023	*1.45*	*1.20*	*2.00*	*1.10*	*5.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.89	.89	.9275	.9275	3.64
2019	.9275	.9275	.945	.945	3.75
2020	.945	.945	.965	.965	3.82
2021	.965	.965	.985	.985	3.90
2022	.985				

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. '21 reported deprec. rate: 2.9%. 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.

An unfavorable ruling from the Indiana Supreme Court has prompted us to cut our 2022 earnings estimate for Duke Energy by $0.25 a share. The court overturned an order from the state commission that had allowed the utility to recover certain coal-ash closure costs. Duke took a pretax charge estimated at $222 million-$245 million against first-quarter results, which were reported shortly after this report went to press. We are *including* this in our earnings presentation because these expenses are operational in nature. (We included a similar charge that Duke took for coal-ash costs in North Carolina in the fourth quarter of 2020.) Our revised estimate of $5.20 a share is below management's targeted range of $5.30-$5.60 because Duke excludes the charge from its guidance.

Earnings will probably advance moderately, despite this charge. Duke also took an unusual charge in 2021, $0.18 a share for a workforce realignment in the June quarter. Some of Duke's utilities are receiving revenues through general rate increases or riders (surcharges) on customers' bills. The company should benefit from growth in kilowatt-hour sales.

We expect a substantial profit increase in 2023. We assume no coal-ash charges. Duke's utilities should benefit from rate relief and volume growth. A $49 million rate hike will take effect in Florida at the start of next year. In Ohio, the company requested an increase of $55 million (3.3%), based on a 10.3% return on equity. An order is expected this summer.

An asset sale is expected to close by January. Duke sold a minority interest in its Indiana utility. The buyer already owns an 11.05% stake, and the remainder will boost its interest to 19.9%. The company is using the $2.05 billion raised in the two sales to offset its equity needs.

The dividend yield of this untimely stock is only slightly above the utility average. Dividend growth prospects through 2025-2027 are subpar due to the high payout ratio. Total return potential is low for the next 18 months and for the 3- to 5-year period. There is some speculative interest once a standstill agreement with Elliott Investment Management expires after November 13th.

Paul E. Debbas, CFA *May 13, 2022*

(A) Dil. EPS. Excl. nonrec. losses: '12, 70¢; '13, 24¢; '14, 67¢; '17, 15¢; '18, 41¢; '20, $2.21; losses on disc. ops.: '14, 80¢; '16, 60¢. '20 EPS don't sum 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 '21: $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%; earned on avg. com. eq., '21: 8.1%. Reg. Clim.: NC, SC Avg.; OH, IN Above Avg.

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

EDISON INTERNAT'L NYSE-EIX

RECENT PRICE 62.50 | P/E RATIO 13.9 (Trailing: 40.6; Median: 17.0) | RELATIVE P/E RATIO 0.90 | DIV'D YLD 4.5% | VALUE LINE

TIMELINESS 3 Raised 9/17/21
SAFETY 3 Lowered 11/23/18
TECHNICAL 2 Raised 6/24/22
BETA .95 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$58-$91 $75 (20%)

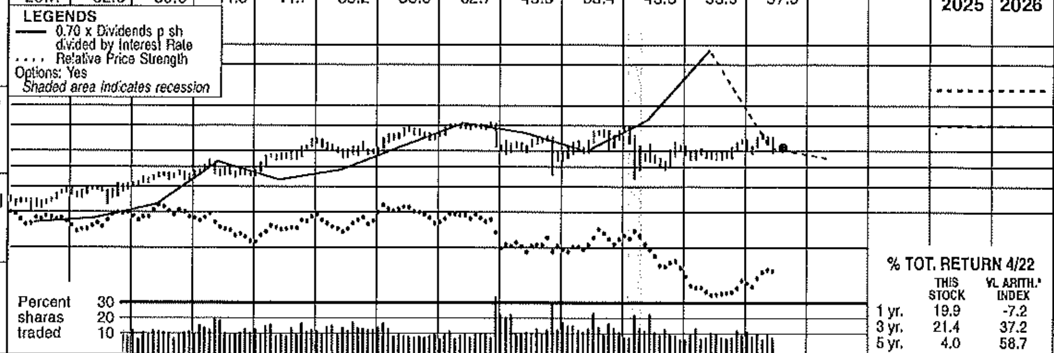
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	120	(+90%)	20%
Low	80	(+30%)	10%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	298	356	323
to Sell	263	252	291
Hld's(000)	332161	335565	332086

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	41.6	48.0	54.2	68.7	69.6	78.7	83.4	71.0	76.4	76.9	68.6	73.3
Low:	32.6	39.6	44.3	44.7	55.2	58.0	62.7	45.5	53.4	43.6	53.9	57.9



% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	19.9	-7.2
3 yr.	21.4	37.2
5 yr.	4.0	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
38.74	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	42.15	42.80	Revenues per sh	47.55
7.25	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	11.05	11.50	"Cash Flow" per sh	13.30
3.28	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	4.50	4.85	Earnings per sh A	6.15
1.10	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	3.00	Div'd Decl'd per sh B ■	3.55
7.78	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	13.25	14.50	Cap'l Spending per sh	16.50
23.66	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	38.60	40.30	Book Value per sh C	48.25
325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	361.99	378.91	380.38	382.00	382.00	Common Shs Outst'g D	385.00
13.0	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	Bold figures are		Avg Ann'l P/E Ratio	16.0
.70	.85	.75	.65	.66	.74	.62	.71	.68	.75	.94	.87	--	.89	1.79	1.63	Value Line		Relative P/E Ratio	.90
2.6%	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%	estimates		Avg Ann'l Div'd Yield	3.6%

CAPITAL STRUCTURE as of 3/31/22
Total Debt $27016 mill. Due in 5 Yrs $9500 mill.
LT Debt $24967 mill. LT Interest $975 mill.
(LT interest earned: 2.9x)
Leases, Uncapitalized Annual rentals $623 mill.
Pension Assets-12/21 $4296 mill. Oblig $4171 mill.
Pfd Stock $3878 mill. Pfd Div'd $211 mill.
350,000 sh. 6.25%, $1000 liq. value; 638,020 sh. 5.0%-5.75%, $2500 liq. value; 1,250,000 sh. 5.375%, 750,000 sh. 5%, $1000 liq. value, all cum.
Common Stock 381,200,287 shs.
as of 4/26/22
MARKET CAP: $23.8 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
11862	12581	13413	11524	11869	12320	12657	12347	13578	14905	16100	16350	Revenues ($mill)	18300
1594.0	1344.0	1539.0	1480.0	1422.0	1603.0	d290.0	1477.0	775.0	925.0	1720	1855	Net Profit ($mill)	2370
14.3%	25.2%	22.4%	6.6%	11.1%	5.0%	--	--	--	--	5.0%	5.0%	Income Tax Rate	5.0%
8.5%	7.8%	5.8%	8.0%	6.8%	7.2%	--	11.1%	22.5%	18.5%	10.0%	9.0%	AFUDC % to Net Profit	7.0%
45.2%	45.7%	44.1%	45.0%	41.8%	45.6%	53.6%	53.5%	55.2%	57.6%	58.0%	58.5%	Long-Term Debt Ratio	60.5%
46.2%	46.2%	47.2%	46.7%	49.2%	45.8%	38.3%	39.9%	39.5%	33.2%	32.0%	31.5%	Common Equity Ratio	34.5%
20422	21516	23216	24352	24362	25506	27284	33360	35581	41959	45000	48000	Total Capital ($mill)	55000
30273	30455	32981	35085	37000	39050	41348	44285	47839	50700	53000	56500	Net Plant ($mill)	63750
8.9%	7.3%	7.7%	7.1%	6.9%	7.3%	.1%	5.6%	3.4%	3.3%	5.5%	5.0%	Return on Total Cap'l	5.5%
14.2%	11.5%	11.9%	11.1%	10.0%	11.6%	NMF	9.5%	4.9%	5.2%	10.5%	10.0%	Return on Shr. Equity	11.0%
15.9%	12.5%	13.0%	12.0%	10.8%	12.7%	NMF	10.2%	4.6%	5.5%	12.5%	11.5%	Return on Com Equity E	13.0%
11.4%	8.1%	8.8%	7.2%	5.6%	6.6%	NMF	4.1%	NMF	NMF	5.0%	4.0%	Retained to Com Eq	5.5%
32%	40%	37%	44%	53%	52%	NMF	63%	NMF	125%	63%	62%	All Div'ds to Net Prof	58%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.7	+.7	-3.9
Avg. Indust. Use (MWH)	657	589	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	22009	23133	21190
Annual Load Factor (%)	49.6	46.7	52.7
% Change Customers (yr-end)	+.5	+.6	+.3
Fixed Charge Cov. (%)	172	NMF	113

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-.5%	-.5%	4.5%
"Cash Flow"	--	-3.5%	7.5%
Earnings	-2.5%	-9.0%	16.0%
Dividends	7.5%	8.5%	5.5%
Book Value	1.5%	1.0%	4.5%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2824	2812	3741	2970	12347
2020	2790	2987	4644	3157	13578
2021	2960	3315	5299	3331	14905
2022	3968	3530	5180	3422	16100
2023	3375	3675	5625	3675	16350

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.64	1.57	1.35	.45	3.98
2020	.50	.85	d.76	1.13	1.72
2021	.68	.84	d.90	1.38	2.00
2022	.22	.90	1.75	1.63	4.50
2023	.90	1.00	1.80	1.15	4.85

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.605	.605	.605	.605	2.42
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		

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, 43%; commercial, 45%; industrial, 3%; other, 9%. Generating sources: nuclear, 8%; gas, 3%; hydro, 3%; purch., 86%. Power costs: 37% of revs. '21 reported depr. rate: 3.7%. Has 13,000 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 is poised for a bounce back year in 2022. The California-based utility was ravaged by wildfires and mudslides in 2017-2018, and the claims related to these disasters hit the company's books in 2020-2021. This year, however, we are not anticipating any fresh claims, and are looking for earnings of $4.50 a share, which excludes roughly $0.40 of amortization expense for Edison's contributions to the wildfire insurance fund. For next year, we think Southern California Edison's rate base will be on the rise. In turn, the profits of the parent company will be propped up as well. Our $4.85 call falls in line with management's goal of 5% to 7% earnings growth per annum.

When all is said and done, Edison International's true earnings results in the coming years are in the hands of the California Public Utilities Commission (CPUC). A mechanism in the cost-of-capital scheme could potentially retroactively trim Edison's ROE for this year from 10.3% to 9.72%. We think the 10.3% figure will be maintained, but that is only one proceeding, a separate regulatory meeting will then take place for an ROE decision on 2023 through 2025.

Much of the news surrounding this company goes back to the wildfires. Another review by management was conducted in the first quarter of this year, which included large damage claims by a small number of plaintiffs. In turn, the in-house estimate for losses was ratcheted up by more than $400 million, to a figure now exceeding $5 billion. Multiple future applications for rate recovery from CPUC are in the cards, with the first filing targeted for late 2023. In the meantime, the overall capital budget should be higher, padded by long-term debt additions, as battery storage operations and the hardening of the grid post-wildfires continue in earnest.

Edison's above-average dividend yield, even for the utility arena, is the draw here. Subscribers should note that this percentage payout is propped up on the uncertainties surrounding the aforementioned wildfires. Looking further out, the total return potential for the coming 18 months is subpar, and EIX also does not distinguish itself for the stretch to 2025-2027.

Erik M. Manning *July 22, 2022*

(A) Dil. EPS. Excl. nonrec. gains (losses): '09, (64¢); '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.: '12, ($5.11); '13, 11¢; '14, 57¢; '15, 11¢; '18, 10¢. '19 EPS don't sum due to change in shs. Next earnings report due July 28th. (B) Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '21: $20.14/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	75
Price Growth Persistence	35
Earnings Predictability	10

ENTERGY CORP. NYSE-ETR

RECENT PRICE 121.08 | P/E RATIO 18.9 (Trailing: 18.4 / Median: 14.0) | RELATIVE P/E RATIO 1.13 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 4 Lowered 12/10/21
SAFETY 2 Raised 12/13/19
TECHNICAL 3 Lowered 6/10/22
BETA .90 (1.00 = Market)

High:	74.5	74.5	72.6	92.0	90.3	82.1	87.9	90.8	122.1	135.5	115.0	126.8
Low:	57.6	61.6	60.2	60.4	61.3	65.4	69.6	71.9	83.2	75.2	85.8	100.2

Target Price Range 2025 | 2026 | 2027

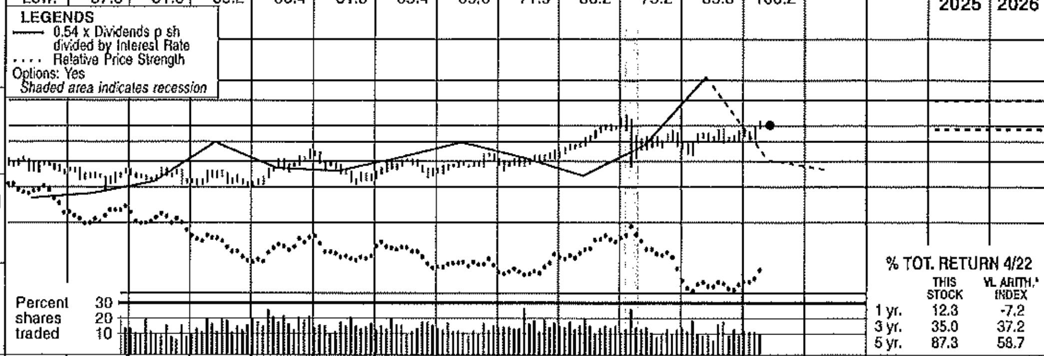
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$103-$155 $129 (5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	160	(+30%)	10%
Low	115	(-5%)	3%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	264	352	327
to Sell	275	244	281
Hld's(000)	183072	182168	179128



% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	12.3	-7.2
3 yr.	35.0	37.2
5 yr.	87.3	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
53.94	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	*56.30*	*56.45*	Revenues per sh	*61.50*
10.69	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	*17.55*	*17.95*	"Cash Flow" per sh	*20.50*
5.36	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	*6.40*	*6.70*	Earnings per sh A	*8.50*
2.16	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	*4.09*	*4.30*	Div'd Decl'd per sh B ■ †	*5.10*
9.44	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	*18.15*	*19.00*	Cap'l Spending per sh	*19.75*
40.45	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	*60.30*	*63.55*	Book Value per sh C	*74.00*
202.67	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	*206.00*	*209.00*	Common Shs Outst'g D	*214.00*
14.3	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	Bold figures are		Avg Ann'l P/E Ratio	*16.0*
.77	1.02	1.00	.80	.74	.57	.71	.74	.68	.63	.57	.75	.75	.88	.79	.80	Value Line		Relative P/E Ratio	*.90*
2.8%	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%	estimates		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $28559 mill. Due in 5 Yrs $11117 mill.
LT Debt $26176 mill. LT Interest $824.0 mill.
Incl. $54.7 mill. of securitization bonds.
(LT interest earned: 2.8x)
Leases, Uncapitalized Annual rentals $65.3 mill.
Pension Assets-12/21 $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 203,374,308 shs. as of 4/29/22
MARKET CAP: $25 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
10302	11391	12495	11513	10846	11074	11009	10879	10114	11743	*11600*	*11800*	Revenues ($mill)	*13150*
1091.9	904.5	1060.0	1061.2	1249.8	950.7	1092.1	1258.2	1406.7	1402.8	*1340*	*1420*	Net Profit ($mill)	*1845*
13.0%	26.7%	37.8%	2.2%	11.3%	1.8%	NMF	NMF	NMF	16.1%	*23.0%*	*23.0%*	Income Tax Rate	*23.0%*
11.9%	10.1%	9.3%	7.4%	8.1%	14.7%	17.5%	16.7%	12.2%	7.1%	*8.0%*	*8.0%*	AFUDC % to Net Profit	*7.0%*
55.8%	55.1%	54.9%	57.8%	63.6%	63.6%	63.2%	62.0%	65.5%	67.6%	*66.5%*	*66.5%*	Long-Term Debt Ratio	*66.0%*
42.9%	43.6%	43.8%	40.8%	35.5%	35.5%	35.9%	37.1%	33.7%	31.7%	*32.5%*	*33.0%*	Common Equity Ratio	*33.5%*
21432	22109	22842	22714	22777	22528	24602	27557	32386	36733	*38050*	*40200*	Total Capital ($mill)	*47300*
27299	27882	28723	27824	27921	29664	31974	35183	38853	42244	*43750*	*45425*	Net Plant ($mill)	*50800*
6.4%	5.4%	6.0%	6.0%	6.9%	5.7%	5.8%	5.9%	5.6%	4.8%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.0%*
11.5%	9.1%	10.3%	11.1%	15.1%	11.6%	12.0%	12.0%	12.6%	11.6%	*10.5%*	*10.5%*	Return on Shr. Equity	*11.5%*
11.6%	9.2%	10.4%	11.2%	15.2%	11.7%	12.2%	12.1%	12.7%	11.9%	*10.5%*	*10.5%*	Return on Com Equity E	*11.5%*
5.2%	3.0%	4.4%	4.8%	7.7%	3.9%	4.9%	5.2%	5.9%	5.2%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
56%	68%	58%	58%	50%	68%	61%	58%	55%	57%	*64%*	*64%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-1.4	-4.1	+3.2
Avg. Indust. Use (MWH)	1070	1017	1015
Avg. Indust. Revs. per KWH(¢)	5.24	4.95	5.91
Capacity at Peak (Mw)	23887	25665	NA
Peak Load, Summer (Mw)	21598	21340	NA
Annual Load Factor (%)	64	62	NA
% Change Customers (yr-end)	+.8	+1.0	+1.0
Fixed Charge Cov. (%)	165	202	243

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.0%	-3.5%	*2.0%*
"Cash Flow"	1.0%	-.5%	*2.5%*
Earnings	--	1.5%	*4.0%*
Dividends	1.5%	2.0%	*5.0%*
Book Value	1.5%	1.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2610	2666	3141	2462	10879
2020	2427	2413	2904	2370	10114
2021	2845	2822	3353	2723	11743
2022	2878	*2822*	*3200*	*2700*	*11600*
2023	*2950*	*2850*	*3250*	*2750*	*11800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.32	1.22	1.82	1.94	6.30
2020	.59	1.79	2.59	1.93	6.90
2021	1.66	1.30	2.63	1.28	6.87
2022	1.36	*1.59*	*2.70*	*.75*	*6.40*
2023	*1.35*	*1.70*	*2.85*	*.80*	*6.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.89	.89	.89	.91	3.58
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			

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, 46%; nuclear, 30%; coal, 6%; purchased, 18%. Fuel costs: 32% of revenues. '21 reported depreciation rate: 2.7%. Has 12,400 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 is making progress in recovering the costs of severe storms in its service area in 2020 and 2021. The company is recovering these capital and operating expenses through the issuance of securitized bonds. Entergy Texas issued $291 million in April, and Entergy Louisiana has received $3.2 billion. Entergy Louisiana expects to get an additional $1.7 billion by yearend, pending approval by the state commission.

The company's last nonutility nuclear plant ceased operations in May. The sale of the unit will likely be completed soon. (The buyer is getting the nuclear decommissioning trust at a significant discount.) Now that Entergy is almost entirely a regulated utility, its business risk is lower. However . . .

Earnings will probably decline this year. The nonutility operations that Entergy is exiting provided $0.61 a share of income in 2021 and $0.04 a share in the first quarter of 2022 (versus $0.19 in the same period a year earlier). Also, average shares outstanding will rise. Entergy's financing plans call for the issuance of $1 billion of common equity from 2022 through 2024. Our 2022 share-earnings estimate of $6.40 is near the upper end of management's targeted range of $6.15-$6.45.

Rate requests under formula rate plans are pending in Mississippi and New Orleans. Entergy Mississippi requested $48.6 million (the utility has a deficiency of $69 million, but the increase is subject to a cap of 4% of retail revenues), and Entergy New Orleans requested $40.2 million. Revenues obtained under formula rate plans are a source of the company's annual earnings growth.

We look for higher profits in 2023. Revenues from formula rate plans are one factor. Also, the service area's economy is showing no signs of slowing, in contrast to the GDP decline in the first quarter. Industrial kilowatt-hour sales advanced 6.5% in the March period. Our earnings estimate remains at the midpoint of Entergy's guidance of $6.55-$6.85 a share.

The dividend of this untimely stock is slightly above average for a utility. The equity lacks appeal for the next 18 months or the 3- to 5-year period.

Paul E. Debbas, CFA *June 10, 2022*

(A) Diluted EPS. 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 Aug. (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 '21: $35.95/sh. (D) In mill. (E) Rate base: Net original cost. Allowed ROE (blended): 9.95%; earned on avg. com. eq., '21: 12.1%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	35
Earnings Predictability	70

EVERGY, INC. NYSE-EVRG

RECENT PRICE 70.57 | P/E RATIO 20.2 (Trailing: 20.0 Median: NMF) | RELATIVE P/E RATIO 1.21 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 5 Lowered 4/29/22
SAFETY 2 New 9/14/18
TECHNICAL 3 Lowered 6/10/22
BETA .90 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$60-$87 $74 (5%)

2025-27 PROJECTIONS

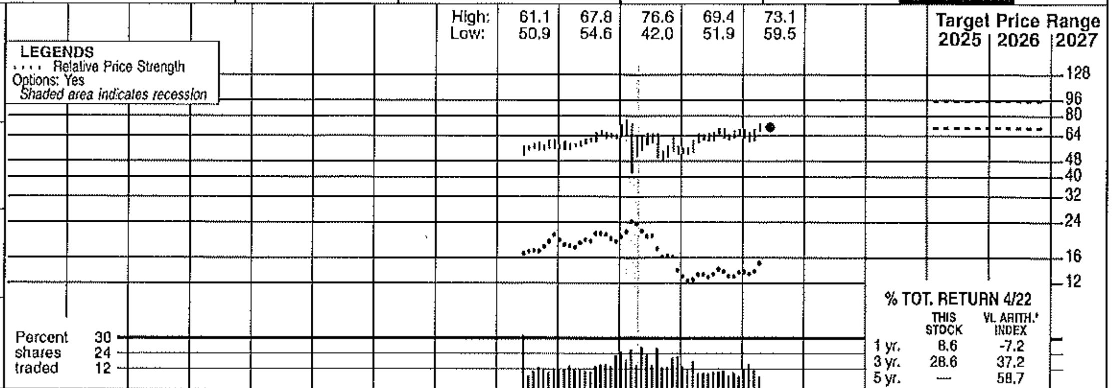
	Price	Gain	Ann'l Total Return
High	95	(+35%)	11%
Low	70	(Nil)	4%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	262	308	284
to Sell	240	237	270
Hld's(000)	204443	206094	196288

	2018	2019	2020	2021	2022
High:	61.1	67.8	76.6	69.4	73.1
Low:	50.9	54.6	42.0	51.9	59.5

LEGENDS
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.6	-7.2
3 yr.	28.6	37.2
5 yr.	—	58.7

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.

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
--	--	--	--	--	--	16.75	22.71	21.66	24.36	23.05	23.70	Revenues per sh	26.50
--	--	--	--	--	--	4.89	7.18	7.06	8.18	7.95	8.40	"Cash Flow" per sh	10.00
--	--	--	--	--	--	2.50	2.79	2.72	3.83	3.50	3.75	Earnings per sh A	4.75
--	--	--	--	--	--	1.74	1.93	2.05	2.18	2.33	2.48	Div'd Decl'd per sh B ■	3.05
--	--	--	--	--	--	4.19	5.34	6.88	8.60	8.60	9.20	Cap'l Spending per sh	9.50
--	--	--	--	--	--	39.28	37.82	38.50	40.32	41.35	42.65	Book Value per sh C	47.25
--	--	--	--	--	--	255.33	226.64	226.84	229.30	230.00	230.00	Common Shs Outst'g D	230.00
--	--	--	--	--	--	22.7	21.8	21.7	16.2	Bold figures are		Avg Ann'l P/E Ratio	17.5
--	--	--	--	--	--	1.23	1.16	1.11	.87	Value Line		Relative P/E Ratio	.95
--	--	--	--	--	--	3.1%	3.2%	3.5%	3.5%	estimates		Avg Ann'l Div'd Yield	3.7%
--	--	--	--	--	--	4275.9	5147.8	4913.4	5586.7	5300	5450	Revenues ($mill)	6100
--	--	--	--	--	--	535.8	669.9	618.3	879.7	820	880	Net Profit ($mill)	1115
--	--	--	--	--	--	9.8%	12.6%	14.1%	11.7%	9.0%	9.0%	Income Tax Rate	9.0%
--	--	--	--	--	--	2.5%	2.5%	5.5%	5.0%	5.0%	6.0%	AFUDC % to Net Profit	5.0%
--	--	--	--	--	--	40.0%	50.6%	51.3%	50.1%	51.5%	51.5%	Long-Term Debt Ratio	53.5%
--	--	--	--	--	--	60.0%	49.4%	48.7%	49.9%	48.5%	48.5%	Common Equity Ratio	46.5%
--	--	--	--	--	--	16716	17337	17924	18542	19675	20175	Total Capital ($mill)	23400
--	--	--	--	--	--	18952	19346	20106	21150	22100	23150	Net Plant ($mill)	26300
--	--	--	--	--	--	4.0%	4.8%	4.5%	5.7%	5.0%	5.5%	Return on Total Cap'l	6.0%
--	--	--	--	--	--	5.3%	7.8%	7.1%	9.5%	8.5%	9.0%	Return on Shr. Equity	10.0%
--	--	--	--	--	--	5.3%	7.8%	7.1%	9.5%	8.5%	9.0%	Return on Com Equity E	10.0%
--	--	--	--	--	--	.6%	2.4%	1.8%	4.1%	3.0%	3.0%	Retained to Com Eq	3.5%
--	--	--	--	--	--	89%	69%	75%	57%	65%	65%	All Div'ds to Net Prof	63%

CAPITAL STRUCTURE as of 3/31/22
Total Debt $11565 mill. Due in 5 Yrs $4388.2 mill.
LT Debt $9247.1 mill. LT Interest $330.2 mill.
Incl. $40.9 mill. finance leases.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $18.8 mill.

Pension Assets-12/21 $1714.7 mill.
Oblig $2561.7 mill.

Pfd Stock None

Common Stock 229,478,276 shs.
as of 4/29/22
MARKET CAP: $16 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	NA	-3.9	+3.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.25	7.14	6.94
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. (%)	305	286	350

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
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
2019	1217	1222	1578	1131	5148
2020	1117	1185	1517	1094	4913
2021	1612	1236	1617	1122	5587
2022	1224	1276	1650	1150	5300
2023	1250	1300	1700	1200	5450

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.39	.57	1.56	.28	2.79
2020	.31	.59	1.60	.22	2.72
2021	.84	.81	1.95	.23	3.83
2022	.53	.72	1.95	.30	3.50
2023	.60	.80	2.05	.30	3.75

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.40	.40	.46	.475	1.74
2019	.475	.475	.475	.505	1.93
2020	.505	.505	.505	.535	2.05
2021	.535	.535	.535	.5725	2.18
2022	.5725				

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, 34%; commercial, 30%; industrial, 11%; wholesale, 13%; other, 12%. Generating sources: coal, 54%; nuclear, 17%; purchased, 29%. Fuel costs: 28% of revenues. '21 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 Missouri have rate cases pending. Missouri Metro filed for an increase of $43.9 million (5.2%) and Missouri West requested a hike of $27.7 million (3.8%). Each utility is seeking a 10% allowed return on equity, based on common-equity ratios of 51.2% and 51.8% for Missouri Metro and Missouri West, respectively. The utilities are seeking to place capital spending in the rate base and recover higher property taxes. These are Evergy's first general rate cases since the company was formed four years ago. The company will try to reach settlement on the applications. New tariffs are expected to take effect on December 6th, so this will have little effect on earnings this year.

Another regulatory matter is pending in Missouri, and others are upcoming in Kansas. Missouri West is seeking approval to issue securitized bonds to recover about $300 million of extraordinary gas and power costs that resulted from a cold spell in February of 2021. An order is expected by October. Evergy's utilities in Kansas plan to file rate cases in 2023.

Earnings will probably decline in 2022, due partly to a tough March-quarter comparison. Last year, the aforementioned cold spell benefited Evergy's energy-marketing subsidiary. This raised pretax profits by $86.6 million in the first period of 2021. Our estimate of $3.50 a share is within management's targeted range (on a GAAP basis) of $3.38-$3.58. So far, the service area's economy still appears to be healthy. The company is benefiting from investment in its transmission system, too.

We estimate a solid earnings increase in 2023. Rate relief in Missouri should be the key factor. Our estimate of $3.75 a share would provide 7% growth over the estimated 2022 tally. Evergy's goal for annual profit growth is 6%-8%.

The dividend yield of this untimely stock is about equal to the utility average. Total return potential is subpar for the next 18 months and for the 3- to 5-year period. Note that a standstill agreement with two investors has expired now that Evergy has held its annual meeting. This adds some speculative interest to this stock. However, we advise against buying the equity solely in the hope of a deal.

Paul E. Debbas, CFA *June 10, 2022*

(A) Diluted earnings. '19 EPS don't sum to full-year total due to rounding. Next earnings report due early August. (B) Dividends paid in mid-March, June, September, and December. ■ Dividend reinvestment plan available. (C) Incl. intangibles. In '21: $4,327.7 mill., $18.87/sh. (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, '21: 9.8%. Regulatory Climate: Average.

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

EVERSOURCE ENERGY NYSE-ES

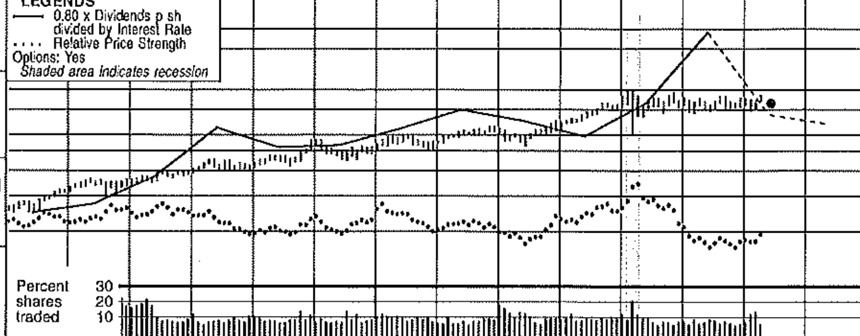
RECENT PRICE 86.18 | P/E RATIO 21.3 (Trailing: 24.3 / Median: 19.0) | RELATIVE P/E RATIO 1.28 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 3 Raised 1/14/22
SAFETY 1 Raised 5/22/15
TECHNICAL 3 Raised 5/13/22
BETA .90 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	36.5	40.9	45.7	56.7	56.8	60.4	66.1	70.5	86.6	99.4	92.7	94.6
Low:	30.0	33.5	38.6	41.3	44.6	50.0	54.1	52.8	63.1	60.7	76.6	78.6

Target Price Range 2025 | 2026 | 2027

LEGENDS
— 0.60 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)
$71-$117 $94 (10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+20%)	8%
Low	85	(Nil)	3%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	360	328	366
to Sell	326	308	312
Hld's(000)	266114	272358	275552

Percent shares traded 30 20 10

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.6	-7.2
3 yr.	31.7	37.2
5 yr.	69.3	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
44.64	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	*29.25*	*29.75*	Revenues per sh	*32.00*
3.69	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	6.89	7.42	*8.10*	*8.45*	"Cash Flow" per sh	*9.75*
.82	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	3.55	3.54	*4.05*	*4.25*	Earnings per sh A	*5.00*
.73	.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*	Div'd Decl'd per sh B ■	*3.20*
5.49	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	*11.25*	*10.50*	Cap'l Spending per sh	*9.50*
18.14	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	*44.30*	*46.30*	Book Value per sh C	*53.00*
154.23	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	*347.00*	*351.00*	Common Shs Outst'g D	*365.00*
27.1	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	24.3	24.2	*Bold figures are*		Avg Ann'l P/E Ratio	*19.5*
1.46	.99	.82	.80	.85	.97	1.27	.95	.94	.91	.98	.98	1.01	1.18	1.25	1.32	*Value Line*		Relative P/E Ratio	*1.10*
3.3%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $20219 mill. Due in 5 Yrs $8313.5 mill.
LT Debt $17477 mill. LT Interest $619.8 mill.
(LT interest earned: 3.6x)
Leases, Uncapitalized Annual rentals $11.1 mill.
Pension Assets-12/21 $6495.5 mill. Oblig $6729.7 mill.
Pfd Stock $155.6 mill. Pfd Div'd $7.6 mill.
Incl. 2,324,000 shs $1.90-$3.28 rates ($50 par) not subject to mandatory redemption, call. at $50.50-$54.00; 430,000 shs 4.25%-4.78% not subject to mandatory redemption, call. at $102.80-$103.63.
Common Stock 344,439,905 shs. as of 1/31/22
MARKET CAP: $30 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
6273.8	7301.2	7741.9	7954.8	7639.1	7752.0	8448.2	8526.5	8904.4	9863.1	*10150*	*10450*	Revenues ($mill)	*11650*
533.0	793.7	827.1	886.0	949.8	995.5	1040.5	1121.0	1212.7	1228.0	*1420*	*1505*	Net Profit ($mill)	*1820*
34.0%	35.0%	36.2%	37.9%	36.9%	36.8%	21.7%	19.7%	22.2%	21.9%	*24.0%*	*24.0%*	Income Tax Rate	*24.0%*
2.3%	1.4%	2.4%	2.9%	3.9%	4.7%	6.1%	6.3%	5.4%	4.5%	*5.0%*	*4.0%*	AFUDC % to Net Profit	*4.0%*
43.7%	44.3%	45.9%	45.6%	44.8%	51.2%	52.4%	52.8%	52.4%	54.2%	*54.5%*	*55.0%*	Long-Term Debt Ratio	*56.0%*
55.4%	54.8%	53.2%	53.6%	54.4%	48.2%	46.9%	46.6%	47.1%	45.3%	*45.0%*	*44.5%*	Common Equity Ratio	*43.5%*
16675	17544	18738	19313	19697	23018	24474	27097	29842	32233	*34325*	*36600*	Total Capital ($mill)	*44500*
16605	17576	18647	19892	21351	23617	25610	27585	30883	33378	*36025*	*38400*	Net Plant ($mill)	*44500*
4.2%	5.5%	5.3%	5.5%	5.8%	5.2%	5.2%	5.1%	5.0%	4.7%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
5.7%	8.1%	8.2%	8.4%	8.7%	8.9%	8.9%	8.8%	8.5%	8.3%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
5.7%	8.2%	8.2%	8.5%	8.8%	8.9%	9.0%	8.8%	8.6%	8.4%	*9.0%*	*9.0%*	Return on Com Equity E	*9.5%*
1.6%	3.4%	3.5%	3.4%	3.5%	3.5%	3.4%	3.6%	3.3%	2.8%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
72%	59%	58%	61%	60%	61%	62%	60%	62%	66%	*64%*	*64%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-3.3	-2.7	+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, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+.8	+.6
Fixed Charge Cov. (%)	319	345	324

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-.5%	2.0%	*3.0%*
"Cash Flow"	3.0%	7.0%	*5.5%*
Earnings	5.5%	5.0%	*6.0%*
Dividends	8.5%	6.5%	*6.0%*
Book Value	6.5%	4.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2415	1884	2175	2050	8526.5
2020	2373	1953	2343	2233	8904.4
2021	2825	2122	2432	2481	9863.0
2022	*2900*	*2200*	*2550*	*2500*	*10150*
2023	*2950*	*2300*	*2650*	*2550*	*10450*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.97	.74	.98	.76	3.45
2020	1.01	.75	1.01	.78	3.55
2021	1.06	.77	.82	.89	3.54
2022	*1.17*	*.87*	*1.08*	*.93*	*4.05*
2023	*1.25*	*.90*	*1.13*	*.97*	*4.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.505	.505	.505	.505	2.02
2019	.535	.535	.535	.535	2.14
2020	.5675	.5675	.5675	.5675	2.27
2021	.6025	.6025	.6025	.6025	2.41
2022	.6375				

BUSINESS: Eversource Energy (formerly Northeast Utilities) is the parent of utilities with 3.3 mill. electric, 887,000 gas, 226,000 water customers. Supplies power to most of Connecticut and gas to part of Connecticut; 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, 33%; industrial, 5%; other, 9%. Fuel costs: 34% of revs. '21 reported depr. rate: 3.1%. Has 9,200 empls. Chairman: James J. Judge. Pres. & CEO: Joseph R. Nolan, Jr. Inc.: MA. Address: 300 Cadwell Drive, Springfield, MA 01104. Tel.: 413-785-5871. Internet: www.eversource.com.

Eversource Energy's earnings will almost certainly rise substantially in 2022. The comparison is easy. Last year, the costs of a regulatory settlement in Connecticut and expenses associated with a gas-utility acquisition reduced share net by $0.32. There will probably still be some transition costs associated with the acquisition, but these should be relatively low and diminish after the second quarter. Besides the easy comparison, Eversource will benefit from transmission spending, which increases the company's earning power annually through a forward-looking regulatory mechanism. In addition, Eversource will benefit from a full year's effect of a gas rate increase in Massachusetts on November 1, 2021 and additional rate relief on November 1, 2022. Our 2022 share-earnings estimate is within management's targeted range of $4.00-$4.17.

An electric rate case is pending in Massachusetts. NSTAR requested increases of $46 million and $47 million at the start of 2023 and 2024, respectively, based on a 10.5% return on equity and a 53.8% common-equity ratio. The utility is also asking for a specific tariff for recovery of a proposed plan to install advanced meters at a cost of $575 million.

We expect further earnings growth in 2023. This is based on continued transmission and further rate relief in Massachusetts. Our estimate would produce 5% profit growth, within Eversource's goal of 5%-7% annually.

Eversource is building offshore wind. The company has joint ventures in three projects, for a total investment of about $9 billion, by 2025. The partners have broken ground on the first project. However, in recent months some costs have been higher than planned. This illustrates offshore wind's construction risk.

The board of trustees raised the dividend in the first quarter. The increase was $0.14 a share (5.8%) annually, the same as in 2021. Eversource's goal for annual dividend hikes is 5%-7%, matching its target for profit growth.

This top-quality stock has a dividend yield that is a cut below the utility average. Total return potential is low for the next 18 months and the 3- to 5-year period.

Paul E. Debbas, CFA *May 13, 2022*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '08, (19¢); '10, 9¢; '19, (64¢). Next earnings report due early Aug. (B) Div'ds historically paid late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '21: $9064 mill., $26.32/sh. (D) In mill. (E) Rate allowed on com. eq. in MA: (elec.) '18, 10.0%; (gas) '20, 9.7%-9.9%; in CT: (elec.) '18, 9.25%; (gas) '18, 9.3%; in NH: '21, 9.3%; earned on avg. com. eq., '21: 8.5%. Regulatory Climate: CT, Below Average; NH, Average; MA, Above Average.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	60
Earnings Predictability	100

EXELON CORP. NDQ-EXC

RECENT PRICE 46.65 | P/E RATIO 20.7 (Trailing: 26.8, Median: 16.0) | RELATIVE P/E RATIO 1.25 | DIV'D YLD 3.0% | VALUE LINE

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

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	45.4	43.7	37.8	38.9	38.3	37.7	42.7	47.4	51.2	50.5	58.0	58.2
Low:	39.1	28.4	26.6	26.5	25.1	26.3	33.3	35.6	43.4	29.3	38.4	40.1

Target Price Range 2025 | 2026 | 2027

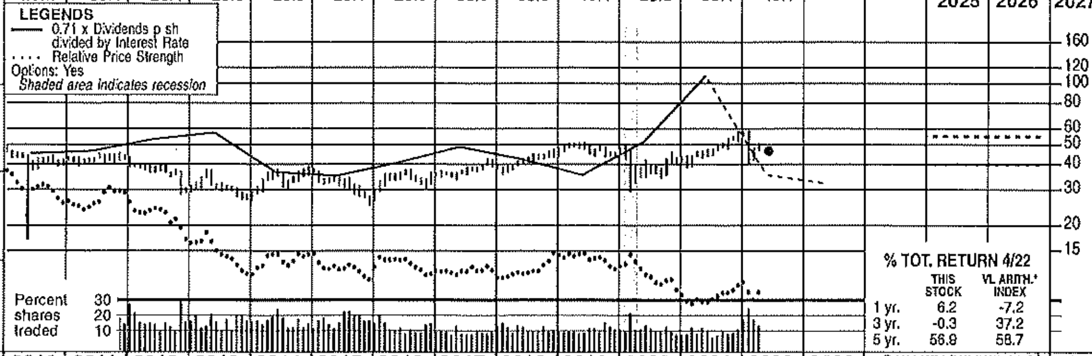
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$29-$57 $43 (-10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+20%)	7%
Low	40	(-15%)	Nil

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	408	413	550
to Sell	387	379	369
Hld's(000)	790477	794682	793215



% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.2	-7.2
3 yr.	-0.3	37.2
5 yr.	56.9	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
23.37	28.62	28.65	28.25	28.17	28.53	27.48	29.03	31.90	32.01	33.94	34.81	37.17	35.39	33.85	37.13	17.80	18.20	Revenues per sh	19.50
6.71	7.43	7.64	8.25	8.32	7.23	6.61	6.72	6.61	6.80	7.01	8.37	8.24	8.96	9.02	9.48	6.55	6.75	"Cash Flow" per sh	7.50
3.50	4.03	4.10	4.29	3.87	3.75	1.92	2.31	2.10	2.54	1.80	2.78	2.07	3.01	2.60	1.74	2.25	2.40	Earnings per sh A	3.00
1.64	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	1.45	Div'd Decl'd per sh B ■	1.80
3.61	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	6.85	6.80	Cap'l Spending per sh	7.00
14.89	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	23.90	25.00	Book Value per sh C	28.75
669.86	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	983.00	988.00	Common Shs Outst'g D	1005.0
16.5	18.2	18.0	11.5	11.0	11.3	19.1	13.4	16.0	12.6	18.7	13.4	20.1	15.7	15.4	27.0	Bold figures are		Avg Ann'l P/E Ratio	16.0
.89	.97	1.08	.77	.70	.71	1.22	.75	.84	.63	.98	.67	1.09	.84	.79	1.47	Value Line		Relative P/E Ratio	.90
2.8%	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%	estimates		Avg Ann'l Div'd Yield	3.7%

CAPITAL STRUCTURE as of 12/31/21
Total Debt $42417 mill. Due in 5 Yrs $12334 mill.
LT Debt $35714 mill. LT Interest $1450 mill.
Includes $390 mill. nonrecourse transition bonds.
(LT interest earned: 2.4x)
Leases, Uncapitalized Annual rentals $156 mill.

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

Common Stock 980,136,968 shs.
as of 1/31/22
MARKET CAP: $46 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
23489	24888	27429	29447	31360	33531	35985	34438	33039	36347	17500	18000	Revenues ($mill)	19500
1579.0	1999.0	1826.0	2282.0	1677.0	2636.0	2010.0	2936.0	2538.0	1706.0	2235	2385	Net Profit ($mill)	3035
32.4%	36.5%	27.2%	32.2%	38.5%	34.2%	5.4%	19.4%	16.4%	16.8%	13.5%	15.0%	Income Tax Rate	15.0%
5.8%	4.5%	5.5%	5.4%	12.3%	6.5%	7.0%	5.3%	6.8%	12.0%	7.0%	6.0%	AFUDC % to Net Profit	5.0%
45.8%	44.4%	46.7%	48.3%	55.5%	52.2%	52.8%	49.6%	52.1%	50.9%	60.0%	61.5%	Long-Term Debt Ratio	64.5%
53.5%	55.2%	52.8%	51.3%	44.5%	47.8%	47.2%	50.4%	47.9%	49.1%	40.0%	38.5%	Common Equity Ratio	35.5%
40057	41196	42811	50272	58053	62422	65229	63943	68068	70107	58550	63925	Total Capital ($mill)	81000
45186	47330	52087	57439	71555	74202	76707	80233	82584	84219	66250	69175	Net Plant ($mill)	77600
5.1%	5.9%	5.3%	5.5%	4.1%	5.3%	4.2%	5.7%	4.8%	3.5%	5.0%	5.0%	Return on Total Cap'l	5.0%
7.3%	8.7%	8.0%	8.8%	6.5%	8.8%	6.5%	9.1%	7.8%	5.0%	9.5%	9.5%	Return on Shr. Equity	10.5%
7.3%	8.7%	8.0%	8.8%	6.5%	8.8%	6.5%	9.1%	7.8%	5.0%	9.5%	9.5%	Return on Com Equity E	10.5%
NMF	3.2%	3.3%	4.5%	1.9%	4.7%	2.2%	4.7%	3.2%	.6%	4.0%	4.0%	Retained to Com Eq	4.5%
109%	63%	59%	49%	70%	47%	66%	48%	59%	88%	59%	60%	All Div'ds to Net Prof	59%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	NA	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	257	211	159

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	2.5%	1.5%	NMF
"Cash Flow"	1.5%	6.0%	NMF
Earnings	-4.5%	2.5%	NMF
Dividends	-3.5%	4.0%	NMF
Book Value	5.0%	4.5%	NMF

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	9477	7689	8929	8343	34438
2020	8747	7322	8853	8117	33039
2021	9890	7915	8910	9632	36347
2022	4800	3900	4550	4250	17500
2023	4950	4000	4700	4350	18000

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.93	.50	.79	.79	3.01
2020	.60	.74	.89	.37	2.60
2021	d.30	.79	1.23	.02	1.74
2022	.60	.45	.70	.50	2.25
2023	.65	.50	.75	.50	2.40

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.345	.345	.345	.345	1.38
2019	.3625	.3625	.3625	.3625	1.45
2020	.3825	.3825	.3825	.3825	1.53
2021	.3825	.3825	.3825	.3825	1.53
2022	.3375				

BUSINESS: Exelon Corporation is a holding company for Commonwealth Edison, PECO Energy, Baltimore Gas and Electric, Pepco, Delmarva Power, & Atlantic City Electric. Has 9.1 mill. elec., 1.3 mill. gas customers. Spun off nonregulated generating & energy-marketing operations 2/22. Acq'd Constellation Energy 3/12; Pepco Holdings 3/16. Elec. revenue breakdown: residential, 54%; small commercial & industrial, 16%; large commercial & industrial, 17%; other, 13%. Fuel costs: 48% of revs. '21 deprec. rates: 2.8%-8.7% elec., 2.1% gas. Has 18,700 empls. Chairman: Mayo A. Shattuck III. Pres. & CEO: Christopher M. Crane. Inc.: PA. Address: 10 S. Dearborn St., P.O. Box 805379, Chicago, IL 60680-5379. Tel.: 312-394-7398. Internet: www.exeloncorp.com.

Exelon is in its first year of operating as a transmission and distribution electric and gas utility. In early February, the company spun off its nonutility operations into a new company, Constellation Energy (NASDAQ: CEG). The nonregulated businesses have faced challenging conditions for the past several years. Exelon stockholders received one share of Constellation for every three shares of Exelon. Due to the corporate separation, the stock is unranked for Timeliness.

Earnings should be less volatile from year to year now that Exelon is entirely a regulated utility. Our 2022 earnings estimate is at the midpoint of management's targeted range of $2.18-$2.32 a share. (Exelon reported first-quarter results shortly after our report went to press.) The company's goal for earnings and dividend growth is 6%-8% annually through 2025. The goal for the payout ratio is 60%. Note that our estimates and projections are not comparable with the historical data shown on the page, which are for Exelon in its previous configuration. In 2021, the company (adjusted for the spinoff) earned $1.95 a share, which included a nickel of separation costs.

Rate relief is a key source of earnings growth. Electric distribution rate hikes took effect in multiple jurisdictions at the start of 2022, and Exelon will benefit from a full year of tariff increases that were granted in mid-2021. The utilities also obtain revenues from various regulatory mechanisms. Modest volume growth should contribute to higher profits, as well. We estimate that share net will advance 7%, to $2.40, next year.

Delmarva Power received a rate increase, and another rate case is pending. In March, the utility received an electric hike of $12.5 million in Maryland, based on a 9.6% return on equity. Delmarva is seeking a $14.5 million gas increase in Delaware, based on a 10.3% ROE. An order is expected in the first quarter of 2023.

The dividend yield of this stock is modest, by utility standards. With the recent quotation well within our 2025-2027 Target Price Range, total return potential is unimpressive.

Paul E. Debbas, CFA *May 13, 2022*

(A) Diluted earnings. Excl. nonrec. gain (losses): '06, ($1.15); '09, (20¢); '12, (50¢); '13, (31¢); '14, 23¢; '16, (58¢); '17, $1.19; '20, (58¢). Next earnings report due early August. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. deferred charges. In '21: $15.22/sh. (D) In mill. (E) Rate all'd on com. eq. in IL in '15: 9.25%; in MD in '16: 9.75% elec., 9.65% gas; in NJ in '16: 9.75%; earned on avg. com. eq., '21: 5.1%. Regulatory Climate: PA, NJ Average; IL, MD, Below Average.

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

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FIRSTENERGY NYSE-FE

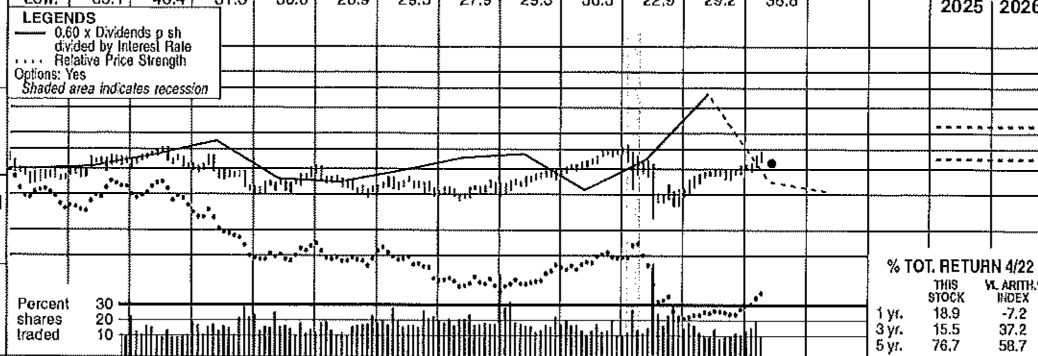
RECENT PRICE 42.94 | P/E RATIO 17.9 (Trailing: 16.7 Median: 19.0) | RELATIVE P/E RATIO 1.08 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 3 Lowered 3/4/22
SAFETY 3 Lowered 7/31/20
TECHNICAL 2 Raised 5/13/22
BETA .80 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	46.5	51.1	46.8	40.8	41.7	36.6	35.2	39.9	49.1	52.5	41.8	48.8
Low:	36.1	40.4	31.3	30.0	28.9	29.3	27.9	29.3	36.3	22.9	29.2	36.8

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

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range
Low-High $28-$47; Midpoint (% to Mid) $38 (-15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+50%)	14%
Low	45	(+5%)	5%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	312	340	349
to Sell	263	211	274
Hld's(000)	449120	447567	477887

Percent shares traded 30 20 10

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	18.9	-7.2
3 yr.	15.5	37.2
5 yr.	76.7	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
36.03	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	*21.15*	*22.10*	Revenues per sh	*25.25*
7.22	8.34	9.04	8.80	8.50	5.75	6.05	6.30	4.55	6.33	6.53	6.54	3.98	3.94	4.05	5.38	*4.95*	*5.30*	"Cash Flow" per sh	*6.50*
3.82	4.22	4.38	3.32	3.25	1.88	2.13	2.97	.85	2.00	2.10	2.73	1.33	1.64	1.85	2.69	*2.40*	*2.60*	Earnings per sh A	*3.25*
1.85	2.05	2.20	2.20	2.20	2.20	2.20	1.65	1.44	1.44	1.44	1.44	1.62	1.53	1.56	1.56	*1.56*	*1.64*	Div'd Decl'd per sh B ■	*2.00*
4.12	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	*5.75*	*5.90*	Cap'l Spending per sh	*6.25*
28.30	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	*16.15*	*17.25*	Book Value per sh C	*21.00*
319.21	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	*572.50*	*575.00*	Common Shs Outst'g D	*582.00*
14.2	15.6	15.6	13.0	11.7	22.4	21.1	13.1	39.8	17.0	15.9	11.4	26.5	23.8	20.2	13.6	*Bold figures are*		Avg Ann'l P/E Ratio	*16.5*
.77	.83	.94	.87	.74	1.41	1.34	.74	2.10	.86	.83	.57	1.43	1.27	1.04	.74	*Value Line*		Relative P/E Ratio	*.90*
3.4%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $23159 mill. Due in 5 Yrs $5795 mill.
LT Debt $21754 mill. LT Interest $972 mill.
Incl. $36 mill. finance leases.
(LT interest earned: 2.6x)
Leases, Uncapitalized Annual rentals $54 mill.

Pension Assets-12/21 $9020 mill. Oblig $11479 mill.

Pfd Stock None

Common Stock 570,932,260 shs.

MARKET CAP: $25 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
15294	14903	15049	15029	14562	14022	11261	11035	10790	11132	*12100*	*12700*	Revenues ($mill)	*14700*
891.0	1245.0	356.0	844.0	892.0	1213.0	726.0	995.0	1003.0	1469.0	*1375*	*1510*	Net Profit ($mill)	*1895*
41.1%	36.1%	5.6%	35.7%	37.8%	37.2%	32.4%	19.0%	11.2%	17.9%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
8.1%	6.0%	33.1%	13.9%	11.5%	6.5%	9.0%	7.1%	7.7%	5.1%	*6.0%*	*5.0%*	AFUDC % to Net Profit	*4.0%*
53.7%	55.5%	60.7%	60.7%	74.5%	84.3%	72.3%	73.8%	75.4%	71.9%	*70.0%*	*69.0%*	Long-Term Debt Ratio	*66.5%*
46.3%	44.5%	39.3%	39.3%	25.5%	15.7%	27.4%	26.2%	24.6%	28.1%	*30.0%*	*31.0%*	Common Equity Ratio	*33.5%*
28263	28523	31596	31613	24433	25040	24565	26593	29368	30923	*30750*	*32275*	Total Capital ($mill)	*36700*
32903	33252	35783	37214	29387	28879	29911	31650	33294	34744	*36625*	*38850*	Net Plant ($mill)	*44300*
4.9%	6.0%	2.7%	4.3%	5.7%	7.0%	4.9%	5.4%	5.0%	6.3%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
6.8%	9.8%	2.9%	6.8%	14.3%	30.9%	10.7%	14.3%	13.9%	16.9%	*15.0%*	*15.0%*	Return on Shr. Equity	*15.5%*
6.8%	9.8%	2.9%	6.8%	14.3%	30.9%	9.7%	14.2%	13.9%	16.9%	*15.0%*	*15.0%*	Return on Com Equity E	*15.5%*
NMF	2.6%	NMF	1.9%	4.5%	14.6%	NMF	2.5%	2.2%	7.1%	*5.0%*	*5.5%*	Retained to Com Eq	*6.0%*
103%	74%	NMF	72%	68%	53%	108%	82%	84%	58%	*65%*	*62%*	All Div'ds to Net Prof	*61%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.7	-4.0	+2.4
Avg. Indust. Use (MWH)	NMF	NMF	NMF
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+.6	+.4
Fixed Charge Cov. (%)	249	203	171

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-7.0%	-10.5%	*4.0%*
"Cash Flow"	-5.5%	-5.0%	*6.0%*
Earnings	-3.0%	5.0%	*7.5%*
Dividends	-3.5%	1.5%	*4.5%*
Book Value	-7.0%	-10.5%	*7.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2883	2516	2963	2673	11035
2020	2709	2522	3022	2537	10790
2021	2726	2622	3124	2660	11132
2022	2989	*2900*	*3400*	*2811*	*12100*
2023	*3150*	*3050*	*3550*	*2950*	*12700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.66	.63	.75	d.20	1.84
2020	.05	.57	.85	.39	1.85
2021	.62	.53	.76	.77	2.69
2022	.51	*.52*	*.76*	*.61*	*2.40*
2023	*.61*	*.57*	*.80*	*.62*	*2.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.36	.36	.36	.36	1.44
2019	.38	.38	.38	.38	1.52
2020	.39	.39	.39	.39	1.56
2021	.39	.39	.39	.39	
2022	.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 6.2 million customers in OH, PA, NJ, WV, MD, & NY. Acq'd Allegheny Energy 2/11. Electric revenue breakdown: residential, 61%; commercial, 25%; industrial, 13%; other, 1%. Purchases most of its power. Power costs: 31% of revenues. '21 reported depreciation rate: 2.7%. Has 12,400 employees. Chairman: Donald T. Misheff. CEO and President: Steven E. Strah. Incorporated: Ohio. Address: 76 South Main Street, Akron, Ohio 44308-1890. Telephone: 800-736-3402. Internet: www.firstenergycorp.com.

FirstEnergy is awaiting the completion of an asset sale. The company agreed to sell a 19.9% stake in its electric transmission subsidiary for $2.375 billion. FirstEnergy raised $1.0 billion from a sale of 25.6 million shares of common stock in December. The majority of the cash is being used to pay down debt. Other options include a pension contribution or funding capital spending. Strengthening the balance sheet is an area of management's focus because some of the company's credit ratings are below investment grade. The transmission sale is expected to close by the end of May.

Share profits will probably decline in 2022. Average shares outstanding will be higher due to the aforementioned stock sale. Due to a regulatory settlement, FirstEnergy will refund $96 million of previously collected revenues and provide $80 million in rate credits to its Ohio customers this year (followed by $60 million in 2023, $45 million in 2024, and $25 million in 2025). In addition, some $150 million of annual corporate costs that were previously capitalized are now being treated as expenses. Our estimate of $2.40 a share is near the low end of FirstEnergy's guidance (on a GAAP basis) of $2.37-$2.57.

We look for a partial earnings recovery next year. The credits in Ohio will be lower. There ought to be a benefit from moderate load growth. Some of the company's capital investments are recoverable through various regulatory mechanisms. We trimmed our estimate by a nickel a share due to the possibility that pension expense will be greater than previously anticipated. We think a resumption of dividend growth is possible, too. FirstEnergy's targeted range for the payout ratio is 55%-65%.

The dividend yield is slightly above the utility average. The possible resumption of dividend growth next year is another advantage. On the other hand, total return potential is negative for the next 18 months and unspectacular for the 2025-2027 period. Moreover, investors should be aware of various audits by state commissions stemming from improper contacts with state legislators in Ohio. This caused the board to replace FirstEnergy's chief executive officer in 2020.

Paul E. Debbas, CFA *May 13, 2022*

(A) Dil. EPS. Excl. nonrec. loss: '13, $2.07; '14, 17¢; '15, 63¢; '16, $16.59; '17, $6.61; '21, 42¢; gains (loss) from disc. ops.: '18, 66¢; '19, (17¢); '20, 14¢; '21, 8¢. '20, '21 EPS don't sum due to chg. in shs. or roundg. Next egs. report due late 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 '21: $9.98/sh. (D) In mill. (E) Rate base: Depr. orig. cost. Rates all'd on com. eq.: 9.6%-11.7%; earned on avg. com. eq., '21: 18.5%. Reg.: OH, Above Avg.; PA, NJ Avg.; MD, WV Below Avg.

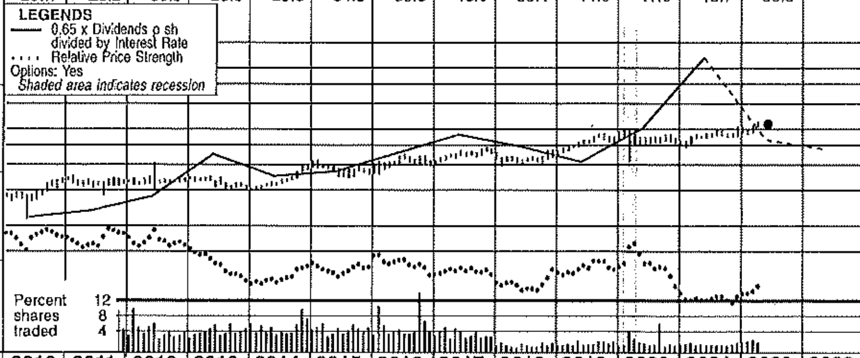
Company's Financial Strength	B+
Stock's Price Stability	80
Price Growth Persistence	25
Earnings Predictability	50

FORTIS INC. TSE-FTS.TO [A]

RECENT PRICE 63.79 | P/E RATIO 23.2 (Trailing: 24.6, Median: 20.0) | RELATIVE P/E RATIO 1.39 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 3 Raised 5/13/22
SAFETY 2 Raised 7/17/15
TECHNICAL 2 Raised 5/20/22
BETA .70 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	35.4	40.7	35.1	40.5	42.1	45.1	48.7	47.4	56.9	59.3	61.6	65.3
Low:	28.2	30.5	29.6	29.8	34.5	36.0	40.6	39.4	44.0	41.6	48.7	56.6



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$56-$84	$70 (10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+35%)	10%
Low	65	(Nil)	4%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	100	126	129
to Sell	112	105	116
Hld's(000)	226561	232396	230539

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.7	-7.2
3 yr.	38.9	37.2
5 yr.	67.1	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
14.14	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	21.60	21.90	Revenues per sh	23.50
3.05	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	6.15	6.40	"Cash Flow" per sh	7.50
1.36	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	2.75	2.90	Earnings per sh [B]	3.50
.67	.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	2.21	2.35	Div'd Decl'd per sh [C] ■	2.80
4.80	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	8.25	7.85	Cap'l Spending per sh	8.25
12.26	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	38.80	40.50	Book Value per sh [D]	46.00
104.09	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	482.00	489.00	Common Shs Outst'g [E]	510.00
17.7	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	Bold figures are	Value Line	Avg Ann'l P/E Ratio	21.5
.96	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	1.13	estimates		Relative P/E Ratio	1.20
2.8%	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%			Avg Ann'l Div'd Yield	3.7%

CAPITAL STRUCTURE as of 3/31/22
Total Debt $26248 mill. Due in 5 Yrs $7732 mill.
LT Debt $24393 mill. LT Interest $945 mill.
Incl. $340 mill. finance leases.
(LT interest earned: 2.4x)
Leases, Uncapitalized Annual rentals $8 mill.

Pension Assets-12/21 $3722 mill. Oblig $3922 mill.
Pfd Stock $1623 mill. Pfd Div'd $65 mill.

Common Stock 476,900,000 shs.

MARKET CAP: $30 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
3654.0	4047.0	5401.0	6727.0	6838.0	8301.0	8390.0	8783.0	8935.0	9448.0	10400	10700	Revenues ($mill)	12000
362.0	390.0	374.0	672.0	660.0	1174.0	1136.0	1238.0	1274.0	1294.0	1380	1475	Net Profit ($mill)	1845
14.1%	7.4%	14.6%	21.3%	16.9%	25.8%	13.4%	12.5%	14.3%	14.3%	14.5%	14.5%	Income Tax Rate	14.5%
5.0%	5.9%	7.2%	7.4%	10.0%	9.5%	8.4%	9.2%	9.3%	9.0%	9.0%	8.0%	AFUDC % to Net Profit	7.0%
55.1%	53.5%	54.8%	53.3%	59.3%	58.4%	58.8%	54.2%	55.6%	55.5%	55.0%	53.5%	Long-Term Debt Ratio	51.5%
35.1%	37.0%	35.7%	38.1%	36.2%	37.1%	37.2%	41.8%	40.5%	40.8%	41.5%	43.0%	Common Equity Ratio	45.0%
11358	12892	19235	21151	35874	36108	40082	40445	42141	43328	44925	46275	Total Capital ($mill)	51900
10249	12267	17816	19595	29337	29668	32654	33988	35998	37816	40125	42250	Net Plant ($mill)	48600
4.8%	4.6%	3.4%	4.5%	2.8%	4.5%	4.1%	4.4%	4.3%	4.2%	4.5%	4.5%	Return on Total Cap'l	5.0%
7.1%	6.5%	4.3%	6.8%	4.5%	7.8%	6.9%	6.7%	6.8%	6.7%	7.0%	7.0%	Return on Shr. Equity	7.5%
7.9%	7.0%	4.5%	7.4%	4.5%	8.3%	7.2%	6.9%	7.1%	7.0%	7.0%	7.0%	Return on Com Equity [F]	7.5%
3.7%	3.2%	1.7%	4.5%	2.1%	5.2%	4.1%	4.0%	2.5%	3.5%	3.5%	3.5%	Retained to Com Eq	4.0%
60%	61%	68%	46%	59%	41%	46%	45%	67%	52%	47%	47%	All Div'ds to Net Prof [G]	47%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% 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. (%)	204	207	211

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-.5%	-1.0%	3.5%
"Cash Flow"	4.0%	6.0%	5.0%
Earnings	5.0%	8.0%	5.0%
Dividends	6.0%	6.5%	6.0%
Book Value	6.5%	5.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2436	1970	2051	2326	8783
2020	2391	2077	2121	2346	8935
2021	2539	2130	2196	2583	9448
2022	2835	2350	2415	2800	10400
2023	2900	2450	2500	2850	10700

Cal-endar	EARNINGS PER SHARE [B] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.72	.54	.63	.77	2.68
2020	.67	.59	.63	.71	2.60
2021	.76	.54	.62	.69	2.61
2022	.74	.59	.67	.75	2.75
2023	.80	.62	.70	.78	2.90

Cal-endar	QUARTERLY DIVIDENDS PAID [C] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.425	.425	.425	.45	1.73
2019	.45	.45	.45	.4775	1.83
2020	.4775	.4775	.4775	.505	1.94
2021	.505	.505	.505	.535	2.05
2022	.535	.535			

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. '21 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 estimate that Fortis will post steady earnings growth this year and next. The company's ITC electric transmission subsidiary benefits from a forward-looking regulatory mechanism that enables the utility to earn a return on its investment contemporaneously and recover most expenses. Fortis' utility in New York will receive the second and third phases of a multiyear rate increase in mid-2022 and mid-2023. This year, the company is planning lower generation maintenance costs. Even so, we trimmed our 2022 share-net estimate by a nickel, to $2.75, because March-quarter profits were slightly below our estimate. We are sticking with our 2023 target of $2.90.

Fortis is hampered by low allowed returns on equity for some of its utilities. This can be seen in the company's earned ROEs, which are low even by utility standards. Tucson Electric Power will soon file a general rate case, and will ask that new tariffs be put into effect by September 1, 2023. Among other things, the utility will request a higher ROE than the currently allowed 9.15%. The cost of capital was reviewed in Alberta, and FortisAlberta will still operate under an 8.5% allowed ROE and a 37% common-equity ratio through 2023. The regulators in British Columbia are examining utilities' cost of capital. ITC's transmission business is allowed healthy ROEs, but the Federal Energy Regulatory Commission might remove a half percentage point incentive "adder" for some transmission owners. This would reduce Fortis' annual earning power by $0.05 a share. We assume no change in ITC's allowed ROE in our estimates and projections.

We expect a dividend increase at the board meeting in September, effective with the payment in December. We look for a hike of $0.13 a share (6.1%) in the annual disbursement. Fortis' goal for the dividend is 6% annual growth through 2025.

This stock has a dividend yield that is slightly above average for a utility. Total return potential is unspectacular for the 18-month and 3- to 5-year periods. Investors interested in dividend reinvestment should note that Fortis offers a 2% discount on its plan.

Paul E. Debbas, CFA *June 10, 2022*

(A) Also trades on NYSE (symbol 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 late Jul. (C) Div'ds histor. pd. early Mar., June, Sept., and Dec. ■ Div'd reinv. plan avail. (2% disc.). (D) Incl. intang. In '21: $34.04/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	45
Earnings Predictability	90

HAWAIIAN ELECTRIC NYSE-HE

RECENT PRICE 40.05 | P/E RATIO 18.6 (Trailing: 17.5 Median: 18.0) | RELATIVE P/E RATIO 1.21 | DIV'D YLD 3.5%

VALUE LINE

TIMELINESS 3 Raised 3/18/22
SAFETY 2 Raised 11/2/12
TECHNICAL 3 Lowered 7/8/22
BETA .80 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$35-$55	$45 (10%)

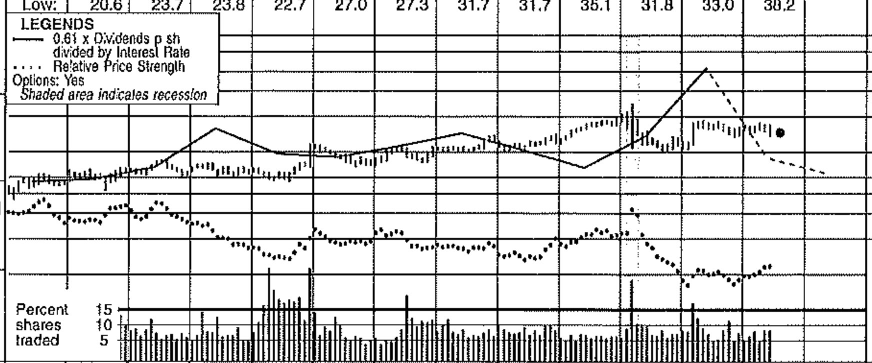
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+25%)	9%
Low	40	(Nil)	4%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	125	156	162
to Sell	117	120	132
Hld's(000)	57595	56043	58052

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	26.8	29.2	28.3	35.0	34.9	35.0	38.7	39.3	47.6	55.2	46.0	44.7
Low:	20.6	23.7	23.8	22.7	27.0	27.3	31.7	31.7	35.1	31.8	33.0	38.2



% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.7	-7.2
3 yr.	8.3	37.2
5 yr.	43.8	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
30.21	30.40	35.56	24.96	28.14	33.76	34.46	31.98	31.59	24.22	21.92	23.49	26.28	26.38	23.63	26.08	*28.20*	*28.50*	Revenues per sh	*31.00*
3.19	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	*4.75*	*5.00*	"Cash Flow" per sh	*5.50*
1.33	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	*2.15*	*2.30*	Earnings per sh A	*2.55*
1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.28	1.32	1.36	*1.40*	*1.44*	Div'd Decl'd per sh B ■	*1.60*
2.58	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	*3.25*	*4.00*	Cap'l Spending per sh	*4.40*
13.44	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	*22.00*	*23.25*	Book Value per sh C	*26.00*
81.46	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	*110.00*	*110.50*	Common Shs Outst'g D	*113.00*
20.3	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	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
1.10	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	1.00	*Value Line*		Relative P/E Ratio	*.95*
4.6%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $2387.6 mill. Due in 5 Yrs $680.0 mill.
LT Debt $2316.1 MILL. LT Interest $105.0 mill.
Incl. $50 mill. 6.5% oblig. pfd. sec. of trust subsid.
(LT interest earned: 3.6x)
Leases, Uncapitalized Annual rentals $11.0 mill.
Pension Assets-12/21 $2320.8 mill. Oblig $2644.6 mill.
Pfd Stock $34.3 mill. Pfd Div'd $2.0 mill.
1,114,657 shs. 4¼% to 5¼%, $20 par. call. $20 to $21; 120,000 shs. 7⅝%, $100 par. call. $100.
Sinking fund ended 2018.
Common Stock 109,431,346 shs. as of 4/25/22
MARKET CAP: $4.4 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
3375.0	3238.5	3239.5	2603.0	2380.7	2555.6	2860.8	2874.6	2579.8	2850.4	*3100*	*3150*	Revenues ($mill)	*3500*
164.9	163.4	170.2	161.8	250.1	180.6	203.7	219.8	199.7	248.1	*235*	*255*	Net Profit ($mill)	*290*
35.9%	34.0%	35.0%	36.5%	33.1%	34.7%	20.0%	19.0%	17.0%	20.2%	*19.0%*	*19.0%*	Income Tax Rate	*19.0%*
6.9%	4.8%	5.5%	5.8%	4.6%	9.6%	7.7%	7.5%	5.9%	5.2%	*6.0%*	*7.0%*	AFUDC % to Net Profit	*6.0%*
45.7%	44.0%	45.2%	43.5%	41.6%	43.4%	47.5%	44.6%	46.5%	46.4%	*47.5%*	*48.0%*	Long-Term Debt Ratio	*49.0%*
53.1%	55.0%	53.8%	55.5%	57.5%	55.7%	51.7%	54.6%	52.7%	52.8%	*52.0%*	*51.5%*	Common Equity Ratio	*50.5%*
3001.0	3142.9	3332.3	3473.5	3595.1	3765.5	4182.3	4176.9	4435.9	4524.1	*4525*	*4770*	Total Capital ($mill)	*5650*
3594.8	3858.9	4148.8	4377.7	4603.5	5025.9	4830.1	5109.6	5265.7	5392.1	*5500*	*5650*	Net Plant ($mill)	*5900*
6.7%	6.4%	6.2%	5.7%	7.9%	5.8%	5.9%	6.3%	5.5%	6.4%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
10.1%	9.3%	9.3%	8.2%	11.9%	8.5%	9.3%	9.5%	8.4%	10.2%	*8.5%*	*8.5%*	Return on Shr. Equity	*9.5%*
10.2%	9.4%	9.4%	8.3%	12.0%	8.5%	9.3%	9.6%	8.5%	10.3%	*8.5%*	*8.5%*	Return on Com Equity E	*9.5%*
4.2%	3.7%	2.3%	1.5%	6.3%	2.1%	3.1%	3.4%	2.3%	4.1%	*3.0%*	*3.0%*	Retained to Com Eq	*3.5%*
59%	61%	75%	83%	48%	76%	67%	64%	73%	61%	*65%*	*63%*	All Div'ds to Net Prof F	*63%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+.6	-7.1	+1.7
Avg. Indust. Use (MWH)	5225	4474	4561
Avg. Indust. Revs. per KWH (¢)	25.52	24.21	26.88
Capacity at Yearend (Mw)	2254	2254	2278
Peak Load, Winter (Mw)	1601	1471	1471
Annual Load Factor (%)	65.2	66.2	67.2
% Change Customers (yr-end)	+.5	+.6	+.5
Fixed Charge Cov. (%)	368	337	393

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.5%	-.5%	*3.5%*
"Cash Flow"	5.0%	5.0%	*3.0%*
Earnings	5.5%	2.0%	*4.0%*
Dividends	.5%	1.5%	*3.5%*
Book Value	3.0%	3.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	661.6	715.5	771.5	726.0	2874.6
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	*730*	*800*	*784.9*	*3100*
2023	*800*	*740*	*815*	*795*	*3150*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.42	.39	.58	.61	1.99
2020	.31	.45	.59	.46	1.81
2021	.59	.58	.58	.50	2.25
2022	.63	*.50*	*.60*	*.42*	*2.15*
2023	*.65*	*.55*	*.65*	*.45*	*2.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.31	.31	.31	.31	1.24
2019	.32	.32	.32	.32	1.28
2020	.33	.33	.33	.33	1.32
2021	.34	.34	.34	.34	1.36
2022	.35	.35			

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 471,000 customers on Oahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Elec. rev. breakdown: residential, 34%; commercial, 34%; large light & power, 32%; other, less than 1%. Generating sources: oil, 52%; purch., 48%. Fuel costs: 46% of revs. '21 reported deprec. rate (utility): 3.2%. Has 3,600 employees. Chairman: Tom Fargo. Pres. & CEO: Scott Seu. Inc.: Hi. Address: 1001 Bishop St., Suite 2900, Honolulu, HI 96808-0730. Tel.: 808-543-5662. Internet: www.hei.com.

Our 2022 earnings estimate for Hawaiian Electric has inched up as the year progresses. The state has moved to a performance-based ratemaking plan and all parties appear to approve of this decision. Along with performance incentives, the mechanism provides revenue annually based on inflation and capital spending of certain types. Still, we do not expect much, if any, growth on the utility front, and the banking arm is apt to need a provision for credit losses, though not as large as we were forecasting to start the year. With that in mind, our share-net call is now up a nickel, to $2.15, though that figure is a dime below the 2021 level.

We think share net can climb by roughly 7% next year. For 2023, we think the utility-related operations will return to growth mode, while the bank benefits from rising interest rates. Subscribers should note, sizable loan loss provisions could ding our $2.30-a-share expectation, and this scenario is in play as the threat of a recession looms.

Renewable energy remains a heavy focus. Proposals are in for an array of projects in this field. Being on an island chain, the company's customer base is behind efforts to fight climate change. In that vein, wind, solar, biomass, and biofuel energy solutions are in the pipeline. Renewable dispatchable energy, a process where the company controls when the resource is used, which includes battery storage, is a goal for 2027. Replacing fossil-fuel generation is key, and the state commission has signed off, with regulatory approval being the next hurdle.

The company has an interim CFO as of July 1st. In late April, Gregory Hazelton, former executive vice president and CFO, announced he was stepping down to pursue other opportunities. Paul Ito is now filling the position on an interim basis, coming over from his previous title of VP of taxes, controller, and treasurer.

This utility's dividend yield is slightly above average when compared to its peers. Still, the stock's quotation is trading just within our Target Price Range out to 2025-2027. Factoring that in, total return potential over the next 18 months and the 3- to 5-year period leaves something to be desired.

Erik M. Manning *July 22, 2022*

(A) Diluted EPS. Excl. nonrec. losses: '07, 9¢; '12, 25¢; '17, 12¢. '19 EPS don't sum due to rounding. Next earnings report due early August. (B) Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '21: $5.32/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	45
Earnings Predictability	80

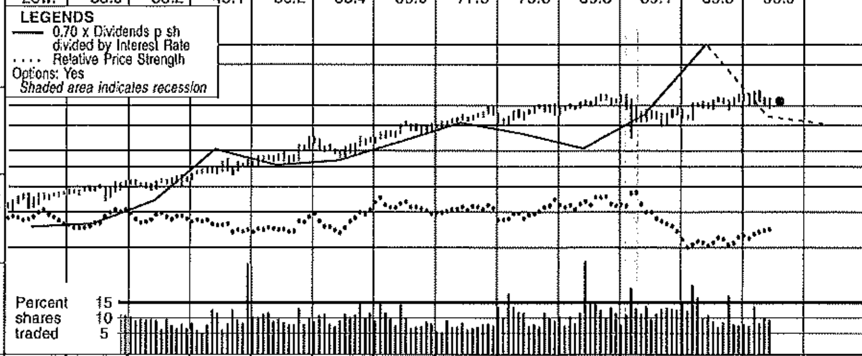
IDACORP, INC. NYSE-IDA

RECENT PRICE 105.60 | P/E RATIO 21.1 (Trailing: 21.7 / Median: 19.0) | RELATIVE P/E RATIO 1.37 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 3 Raised 5/20/22
SAFETY 1 Raised 1/22/21
TECHNICAL 3 Lowered 7/15/22
BETA .80 (1.00 = Market)

High: 42.7	45.7	54.7	70.1	70.5	83.4	100.0	102.4	114.0	113.6	113.8	118.9
Low: 33.9	38.2	43.1	50.2	55.4	65.0	77.5	79.6	89.3	69.1	85.3	96.9

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



Target Price Range 2025 | 2026 | 2027

18-Month Target Price Range
Low-High: $94-$145
Midpoint (% to Mid): $120 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	130	(+25%)	8%
Low	105	(Nil)	3%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	163	208	181
to Sell	145	137	164
Hld's(000)	39867	39410	39894

Percent shares traded 15 10 5

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.7	-7.2
3 yr.	13.8	37.2
5 yr.	40.5	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
21.23	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	*29.20*	*29.60*	Revenues per sh	*34.60*
4.58	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	*8.70*	*9.00*	"Cash Flow" per sh	*10.30*
2.35	1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.85	3.87	3.94	4.21	4.49	4.61	4.69	4.85	*5.00*	*5.20*	Earnings per sh A	*6.00*
1.20	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	*3.05*	*3.25*	Div'd Decl'd per sh B ■ †	*4.00*
5.16	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	*9.50*	*13.25*	Cap'l Spending per sh	*10.00*
25.77	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	*54.55*	*56.00*	Book Value per sh C	*63.45*
43.63	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	*50.70*	*51.00*	Common Shs Outst'g D	*52.00*
15.1	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	*Bold figures are*		Avg Ann'l P/E Ratio	*19.5*
.82	.97	.84	.68	.75	.72	.79	.75	.77	.82	1.00	1.04	1.11	1.19	1.02	1.14	*Value Line*		Relative P/E Ratio	*1.10*
3.4%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $2050.6 mill. Due in 5 Yrs $270.0 mill.
LT Debt $2050.6 mill. LT Interest $90.0 mill.
(LT interest earned: 4.0x)

Pension Assets-12/21 $984.5 mill.
Oblig $1346.5 mill.

Pfd Stock None

Common Stock 50,559,164 shs.
as of 4/29/22

MARKET CAP: $5.3 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
1080.7	1246.2	1282.5	1270.3	1262.0	1349.5	1370.8	1346.4	1350.7	1458.1	*1480*	*1510*	Revenues ($mill)	*1800*
168.9	182.4	193.5	194.7	198.3	212.4	226.8	232.9	237.4	245.6	*255*	*265*	Net Profit ($mill)	*310*
13.4%	28.3%	8.0%	19.0%	15.5%	18.6%	7.1%	9.5%	10.8%	13.1%	*13.0%*	*13.0%*	Income Tax Rate	*13.0%*
20.3%	12.3%	13.6%	16.3%	16.3%	13.9%	15.2%	16.2%	17.3%	17.7%	*20.0%*	*21.0%*	AFUDC % to Net Profit	*16.0%*
45.5%	46.6%	45.3%	45.6%	44.8%	43.7%	43.6%	41.3%	43.9%	42.8%	*44.5%*	*48.5%*	Long-Term Debt Ratio	*50.5%*
54.5%	53.4%	54.7%	54.4%	55.2%	56.3%	56.4%	58.7%	56.1%	57.2%	*55.5%*	*51.5%*	Common Equity Ratio	*49.5%*
3225.4	3465.9	3567.6	3783.3	3898.5	3997.5	4205.1	4201.3	4560.4	4669.1	*4975*	*5530*	Total Capital ($mill)	*6700*
3536.0	3665.0	3833.5	3992.4	4172.0	4283.9	4395.7	4531.5	4709.5	4901.8	*5300*	*5800*	Net Plant ($mill)	*6700*
6.5%	6.4%	6.6%	6.2%	6.1%	6.3%	6.4%	6.5%	6.1%	6.2%	*6.0%*	*5.5%*	Return on Total Cap'l	*6.0%*
9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	9.6%	9.4%	9.3%	9.2%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	9.6%	9.4%	9.3%	9.2%	*9.0%*	*9.0%*	Return on Com Equity E	*9.5%*
5.7%	5.6%	5.4%	4.8%	4.3%	4.4%	4.4%	4.2%	3.9%	3.7%	*3.5%*	*3.0%*	Retained to Com Eq	*3.0%*
41%	43%	46%	50%	53%	53%	54%	56%	58%	60%	*61%*	*63%*	All Div'ds to Net Prof	*67%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-.3	+2.0	+3.9
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.32	5.38	5.62
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3242	3392	3751
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+2.5	+2.7	+2.8
Fixed Charge Cov. (%)	307	313	334

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	2.5%	1.5%	*4.0%*
"Cash Flow"	4.5%	4.0%	*4.0%*
Earnings	4.5%	4.0%	*4.0%*
Dividends	8.5%	7.0%	*6.5%*
Book Value	5.0%	4.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	350.3	316.9	386.3	292.9	1346.4
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	*365*	*450*	*320.7*	*1480*
2023	*345*	*370*	*460*	*335*	*1510*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.84	1.05	1.78	.93	4.61
2020	.74	1.19	2.02	.74	4.69
2021	.89	1.38	1.93	.65	4.85
2022	.91	*1.35*	*2.00*	*.74*	*5.00*
2023	*.95*	*1.40*	*2.05*	*.80*	*5.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.59	.59	.59	.63	2.40
2019	.63	.63	.63	.67	2.56
2020	.67	.67	.67	.71	2.72
2021	.71	.71	.71	.75	2.88
2022	.75	.75			

BUSINESS: IDACORP, Inc. is a holding company for Idaho Power Company, a regulated electric utility that serves 604,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon (population: 1.3 million). Most of the company's revenues are derived from the Idaho portion of its service area. Revenue breakdown: residential, 45%; commercial, 24%; industrial, 15%; irrigation, 13%; other, 3%. Generating sources: hydro, 30%; coal, 17%; gas, 15%; purchased, 38%. Fuel costs: 36% of revenues. '21 reported depreciation rate: 2.9%. Has 2,000 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 appears poised to have another good year in 2022. Earnings growth from this utility is on a good annual run, powered by population growth and healthy economies in its service areas. Weather-related usage is rising, as is transmission wheeling revenues. The company has maintained its 2022 earnings guidance range of $4.85-$5.05 a share, and our $5.00 target is near the spread's apex. This bracket assumes two things, normal weather conditions and Idaho Power not utilizing additional tax credits available under its regulatory mechanism this year. Our 2023 EPS target of $5.20 implies a 4% gain, given the same positives listed.

Rate cases may be on the table for 2023. It has been a decade since Idaho Power filed a rate application. Over that span, customer growth was plentiful and operations were supported. Presently, the capital budget is on the rise, as an ownership position in a transmission line is increasing and battery storage financing demands are rising (more details below). IDACORP's debt burden should move higher in tandem, with the probability of an issuance of equity growing for 2024.

The company is making moves to avoid a possible power capacity deficit. IDA has partnered with Powin, a Portland-area battery energy storage system company on two contracts totaling 120 megawatts of generating capacity. The summer is a concern, as air conditioning and irrigation are prime drivers of usage. The plan is to charge the batteries early in the day, then discharge them in the evening when solar power goes away and wind power is minimal. IDACORP is seeking approval from the Idaho Public Utilities Commission to acquire the battery systems, and it also must get clearance in Oregon because its service territory expands into the east of that state.

IDACORP's high-quality stock is not all that appealing at this juncture. For starters, the dividend yield is below the utility average. Add to this, the quotation is hovering around the bottom rung of our 3- to 5-year Target Price Range, which has rendered long-term total return potential subpar. That metric also gives us a below-average reading for the coming 18-month period for this neutrally ranked selection.

Erik M. Manning *July 22, 2022*

(A) Diluted EPS. Excl. nonrecurring gain: '06, 17¢. '19 earnings don't sum due to rounding. Next earnings report due last week of July. (B) Dividends historically paid in late Feb., May, Aug., and Nov. ■ Dividend reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '21: $1,462.4 mill., $28.95/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on common equity in '12: 10% (imputed); earned on avg. com. eq., '21: 9.4%. Regulatory Climate: Above Average.

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

MGE ENERGY INC. NDQ–MGEE

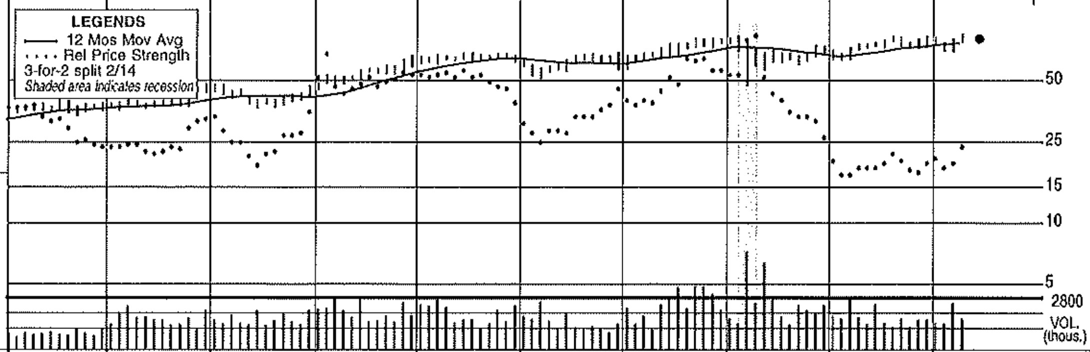
RECENT PRICE 80.73 | TRAILING P/E RATIO 27.7 | RELATIVE P/E RATIO 1.79 | DIV'D YLD 1.9% | VALUE LINE

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	
	40.46	48.00	47.97	66.85	68.70	68.95	80.84	83.26	82.95	84.97	High
	33.39	35.66	36.46	44.82	60.30	51.05	56.74	47.20	63.00	69.23	Low

RANKS

PERFORMANCE 2 Above Average
Technical 2 Above Average
SAFETY 1 Highest
BETA .70 (1.00 = Market)

Financial Strength A+
Price Stability 100
Price Growth Persistence 60
Earnings Predictability 100



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© VALUE LINE PUBLISHING LLC	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022/2023
REVENUES PER SH	17.04	17.88	16.27	15.71	16.24	16.15	16.41	14.89	16.77	
"CASH FLOW" PER SH	3.28	3.49	3.33	3.47	3.73	4.06	4.57	4.61	5.05	
EARNINGS PER SH	2.16	2.32	2.06	2.18	2.20	2.43	2.51	2.60	2.92	***3.13***[A,B]***/3.32***[C]
DIV'D DECL'D PER SH	1.07	1.11	1.16	1.21	1.26	1.32	1.38	1.45	1.52	
CAP'L SPENDING PER SH	3.43	2.67	2.08	2.41	3.12	6.12	4.73	5.62	4.24	
BOOK VALUE PER SH	17.81	19.02	19.92	20.89	22.45	23.56	24.68	26.99	28.41	
COMMON SHS OUTST'G (MILL)	34.67	34.67	34.67	34.67	34.67	34.67	34.67	36.16	36.16	
AVG ANN'L P/E RATIO	17.0	17.2	20.3	24.9	29.4	25.1	28.4	26.4	25.5	***25.8/24.3***
RELATIVE P/E RATIO	.96	.91	1.05	1.36	1.47	1.42	1.65	1.55	1.56	
AVG ANN'L DIV'D YIELD	2.9%	2.8%	2.8%	2.2%	2.0%	2.2%	1.9%	2.1%	2.0%	
REVENUES ($MILL)	590.9	619.9	564.0	544.7	563.1	559.8	568.9	538.6	606.6	***Bold figures***
NET PROFIT ($MILL)	74.9	80.3	71.3	75.6	76.1	84.2	86.9	92.4	105.8	***are consensus***
INCOME TAX RATE	37.5%	37.5%	36.7%	36.0%	36.4%	24.6%	18.5%	17.4%	3.7%	***earnings***
AFUDC % TO NET PROFIT	5.6%	5.7%	1.3%	2.1%	2.1%	5.2%	3.6%	8.7%	6.3%	***estimates***
LONG-TERM DEBT RATIO	39.3%	37.5%	36.2%	34.6%	33.8%	37.7%	38.0%	35.5%	38.1%	***and, using the***
COMMON EQUITY RATIO	60.7%	62.5%	63.8%	65.4%	66.2%	62.3%	62.0%	64.5%	61.9%	***recent prices,***
TOTAL CAPITAL ($MILL)	1016.9	1054.7	1081.5	1106.9	1176.3	1310.0	1379.4	1512.8	1659.0	***P/E ratios.***
NET PLANT ($MILL)	1160.2	1208.1	1243.4	1282.1	1341.4	1509.4	1642.7	1769.4	1878.8	
RETURN ON TOTAL CAP'L	8.3%	8.6%	7.5%	7.7%	7.3%	7.2%	7.1%	6.8%	7.1%	
RETURN ON SHR. EQUITY	12.1%	12.2%	10.3%	10.4%	9.8%	10.3%	10.2%	9.5%	10.3%	
RETURN ON COM EQUITY	12.1%	12.2%	10.3%	10.4%	9.8%	10.3%	10.2%	9.5%	10.3%	
RETAINED TO COM EQ	6.1%	6.4%	4.5%	4.7%	4.2%	4.7%	4.6%	4.2%	5.0%	
ALL DIV'DS TO NET PROF	50%	48%	56%	55%	57%	54%	55%	56%	52%	

[A]No. of analysts changing earn. est. in last 31 days: 0 up, 0 down, consensus 5-year earnings growth 6.1% per year. [B]Based upon 2 analysts' estimates. [C]Based upon one analyst's estimate.

ANNUAL RATES

of change (per share)	5 Yrs.	1 Yr.
Revenues	-0.5%	12.5%
"Cash Flow"	6.5%	9.5%
Earnings	4.0%	12.5%
Dividends	4.5%	5.0%
Book Value	6.0%	5.5%

Fiscal Year	QUARTERLY SALES ($mill.) 1Q	2Q	3Q	4Q	Full Year
12/31/19	167.6	122.2	138.2	140.9	568.9
12/31/20	149.9	117.0	135.2	136.5	538.6
12/31/21	167.9	130.7	145.9	162.1	606.6
12/31/22	208.9				

Fiscal Year	EARNINGS PER SHARE 1Q	2Q	3Q	4Q	Full Year
12/31/18	.58	.53	.85	.47	2.43
12/31/19	.69	.45	.88	.49	2.51
12/31/20	.75	.53	.88	.44	2.60
12/31/21	.96	.63	.97	.36	2.92
12/31/22	.95	*.65*	*.94*	*.64*	

Cal-endar	QUARTERLY DIVIDENDS PAID 1Q	2Q	3Q	4Q	Full Year
2019	.338	.338	.352	.352	1.38
2020	.352	.353	.37	.37	1.45
2021	.37	.37	.387	.388	1.52
2022	.388	.388			

INSTITUTIONAL DECISIONS

	3Q'21	4Q'21	1Q'22
to Buy	69	87	79
to Sell	62	57	69
Hld's(000)	18137	18213	16481

ASSETS ($mill.)	2020	2021	3/31/22
Cash Assets	44.7	17.4	26.4
Receivables	48.7	62.3	50.2
Inventory (Avg cost)	47.3	52.0	42.9
Other	68.8	67.7	74.9
Current Assets	209.5	199.4	194.4
Property, Plant & Equip, at cost	2564.9	2590.4	--
Accum Depreciation	795.5	711.6	--
Net Property	1769.4	1878.8	1883.3
Other	274.8	293.7	299.8
Total Assets	2253.7	2371.9	2377.5
LIABILITIES ($mill.)			
Accts Payable	54.6	64.1	44.7
Debt Due	57.3	10.4	4.9
Other	79.0	43.3	48.5
Current Liab	190.9	117.8	98.1

LONG-TERM DEBT AND EQUITY as of 3/31/22

Total Debt $618.0 mill. Due in 5 Yrs. NA
LT Debt $613.1 mill.
Including Cap. Leases NA
(37% of Cap'l)
Leases, Uncapitalized Annual rentals NA

Pension Liability $73.1 mill. in '21 vs. $78.2 mill. in '20

Pfd Stock None Pfd Div'd Paid None

Common Stock 36,163,000 shares
(63% of Cap'l)

INDUSTRY: Electric Util. (Central)

BUSINESS: MGE Energy is an investor-owned public utility holding company. The company's segments include: regulated electric utility operations, which generates, purchases, and distributes electricity through its subsidiary, Madison Gas and Electric Company (MGE); regulated gas utility operations, which purchases and distributes natural gas through MGE; nonregulated energy operations, which owns and leases electric generating capacity that assists MGE through the company's subsidiaries MGE Power Elm Road, LLC and MGE Power West Campus, LLC; and transmission investments, in which MGE Energy. invests in American Transmission Company, LLC, a company that provides electric transmission services in Wisconsin. Madison Gas and Electric, generates and distributes electricity to 159,000 customers in Dane County, Wisconsin., and purchases and distributes natural gas to 169,000 customers in seven south-central and western Wisconsin counties. Has 706 employees. Chairman, C.E.O. & President: Jeffrey M. Keebler Address: 133 South Blair Street, Madison, WI 53788. Tel.: (608) 252-7000. Internet: www.mgeenergy-.com. *L.Y.*

June 10, 2022

TOTAL SHAREHOLDER RETURN

Dividends plus appreciation as of 4/30/2022

3 Mos.	6 Mos.	1 Yr.	3 Yrs.	5 Yrs.
1.11%	2.87%	5.36%	21.16%	33.18%

NEXTERA ENERGY NYSE-NEE

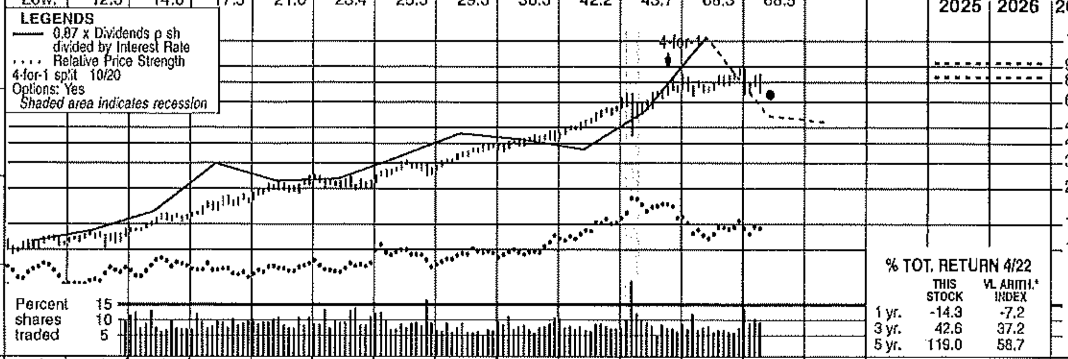
RECENT PRICE 69.87 | P/E RATIO 32.5 (Trailing: NMF; Median: 21.0) | RELATIVE P/E RATIO 1.96 | DIV'D YLD 2.5% | VALUE LINE

TIMELINESS 3 Lowered 4/1/22
SAFETY 1 Raised 2/16/18
TECHNICAL 1 Raised 5/13/22
BETA .90 (1.00 = Market)

High:	15.3	18.1	22.4	27.7	28.2	33.0	39.8	46.1	61.3	83.3	93.7	93.6
Low:	12.3	14.6	17.5	21.0	23.4	25.5	29.3	36.3	42.2	43.7	68.3	68.5

Target Price Range 2025 | 2026 | 2027

LEGENDS
— 0.87 x Dividends p sh divided by Interest Rate
.... 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)
$61-$136 $99 (40%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+45%)	12%
Low	85	(+20%)	8%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	1106	1025	1210
to Sell	799	850	831
Hld's(000)	1473629	1493769	1508954

Percent shares traded 15 10 5

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-14.3	-7.2
3 yr.	42.6	37.2
5 yr.	119.0	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
9.69	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	*8.45*	*9.45*	Revenues per sh	*11.50*
1.69	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	4.31	3.97	*4.40*	*5.25*	"Cash Flow" per sh	*6.50*
.81	.82	1.02	.99	1.19	1.21	1.14	1.21	1.40	1.52	1.45	1.63	1.67	1.94	2.10	1.81	*2.15*	*3.00*	Earnings per sh A	*4.00*
.38	.41	.45	.47	.50	.55	.60	.66	.73	.77	.87	.98	1.11	1.25	1.40	1.54	*1.70*	*1.87*	Div'd Decl'd per sh B ■ †	*2.50*
2.31	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	*8.10*	*8.40*	Cap'l Spending per sh	*10.00*
6.12	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	*19.70*	*22.60*	Book Value per sh C	*26.50*
1621.6	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	*1980.0*	*2025.0*	Common Shs Outst'g D	*2025.0*
13.7	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	31.8	44.2	*Bold figures are*		Avg Ann'l P/E Ratio	*23.0*
.74	1.00	.87	.89	.69	.72	.92	.93	.91	.85	1.09	1.09	1.34	1.43	1.63	2.40	*Value Line*		Relative P/E Ratio	*1.30*
3.4%	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%	*estimates*		Avg Ann'l Div'd Yield	*2.7%*
						14256	15136	17021	17486	16155	17195	16727	19204	17997	17069	*16700*	*19100*	Revenues ($mill)	*23400*
						1911.0	2062.0	2465.0	2752.0	2693.0	3074.0	3200.0	3769.0	4127.0	3573.0	*3710*	*5475*	Net Profit ($mill)	*7425*
						26.6%	26.9%	32.3%	30.8%	29.3%	24.4%	28.6%	11.7%	9.0%	11.0%	*11.0%*	*11.0%*	Income Tax Rate	*11.0%*
						10.8%	7.0%	6.7%	6.9%	8.2%	6.7%	6.6%	3.9%	4.2%	7.4%	*7.0%*	*5.0%*	AFUDC % to Net Profit	*4.0%*
						59.1%	57.1%	55.0%	54.2%	53.3%	52.7%	44.0%	50.4%	53.5%	57.8%	*58.5%*	*56.5%*	Long-Term Debt Ratio	*57.0%*
						40.9%	42.9%	45.0%	45.8%	46.7%	47.3%	56.0%	49.6%	46.5%	42.2%	*41.5%*	*43.5%*	Common Equity Ratio	*43.0%*
						39245	42009	44283	49255	52159	59671	60926	74548	78457	88162	*93975*	*105575*	Total Capital ($mill)	*124500*
						49413	52720	55705	61386	66912	72416	70334	82010	91803	99348	*110925*	*123300*	Net Plant ($mill)	*165200*
						6.2%	6.2%	7.0%	6.8%	6.3%	6.3%	6.3%	6.0%	6.0%	4.8%	*4.5%*	*6.0%*	Return on Total Cap'l	*7.0%*
						11.9%	11.4%	12.4%	12.2%	11.1%	10.9%	9.4%	10.2%	11.3%	9.6%	*9.5%*	*12.0%*	Return on Shr. Equity	*14.0%*
						11.9%	11.4%	12.4%	12.2%	11.1%	10.9%	9.4%	10.2%	11.3%	9.6%	*9.5%*	*12.0%*	Return on Com Equity E	*14.0%*
						5.6%	5.2%	6.0%	6.1%	4.4%	4.4%	3.2%	3.7%	3.8%	1.5%	*2.5%*	*5.0%*	Retained to Com Eq	*5.5%*
						53%	54%	51%	50%	60%	60%	66%	64%	66%	85%	*90%*	*68%*	All Div'ds to Net Prof	*68%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $59693 mill. Due in 5 Yrs $26264 mill.
LT Debt $50974 mill. LT Interest $1402 mill.

(LT interest earned: 3.3x)

Pension Assets-12/21 $5688 mill. Oblig $3445 mill.

Pfd Stock None

Common Stock 1,964,499,706 shs.

MARKET CAP: $137 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+1.7	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.39	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)	+1.8	NA	NA
Fixed Charge Cov. (%)	230	235	203

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	--	--	3.5%
"Cash Flow"	6.0%	5.5%	7.5%
Earnings	5.5%	6.0%	12.5%
Dividends	10.5%	12.0%	10.0%
Book Value	8.5%	9.0%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	4075	4970	5572	4587	19204
2020	4613	4204	4785	4395	17997
2021	3726	3927	4370	5046	17069
2022	2890	*4500*	*4900*	*4410*	*16700*
2023	*4450*	*4800*	*5200*	*4650*	*19100*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.35	.64	.45	.50	1.94
2020	.21	.65	.62	.62	2.10
2021	.84	.13	.23	.61	1.81
2022	.08	*.75*	*.82*	*.50*	*2.15*
2023	*.80*	*.80*	*.90*	*.50*	*3.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.2775	.2775	.2775	.2775	1.11
2019	.3125	.3125	.3125	.3125	1.25
2020	.35	.35	.35	.35	1.40
2021	.385	.385	.385	.385	1.54
2022	.425				

BUSINESS: NextEra Energy, Inc. (formerly FPL Group, Inc.) is a holding company for Florida Power & Light Company (FPL), which provides electricity to 5.6 million customers in eastern, southern, & northwestern Florida. NextEra Energy Resources is a nonragulated power generator with nuclear, gas, & renewable ownership. Has 55% stake in NextEra Energy Partners. Revenue breakdown: residential, 55%; commercial, 33%; industrial & other, 12%. Generating sources: gas, 73%; nuclear, 22%; other, 3%; purchased, 2%. Fuel costs: 27% of revs. '21 depreciation rate: 3.3%. Has 15,000 employees. Chairman: James L. Robo. 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's solar business is facing a challenge. The company's nonutility subsidiary, NextEra Energy Resources, is a major player in renewable energy. Its utility, Florida Power and Light, is also expanding its solar capacity. However, the U.S. Department of Commerce is investigating the importation of solar panels from four countries in Southeast Asia, with the possibility of imposing additional tariffs. Some projects (totaling 2.1-2.8 gigawatts) might be delayed from 2022 to 2023 due to supply-chain problems. Inflation is also a problem. Nevertheless, NextEra did not adjust its 2022 earnings guidance of $2.75-$2.85 a share. Even so, the market is worried about this, and the stock price is 14% below its level on the day before the announcement.

Our earnings estimates require an explanation. We *include* certain items (most notably mark-to-market accounting gains or losses and unrealized gains or losses on the nonutility nuclear decommissioning funds) that NextEra excludes from its earnings guidance. The mark-to-market pretax accounting charge was $1.5 billion in the first quarter. This is why earnings were depressed, and why our estimate of $2.15 a share is well below the company's targeted range. The utility operations are healthy and benefiting from rate relief, so we are sticking with our 2023 earnings estimate of $3.00 a share. However, our expectations for this year and next might well prove optimistic if dealing with the solar-related problems proves more difficult than management expects.

NextEra has written off its investment in a gas pipeline project. Litigation has caused significant delays and cost overruns. The charge was $0.30 a share, which we excluded from our earnings presentation as a nonrecurring item.

The board of directors raised the dividend in the first quarter. The increase was $0.04 a share (10.4%) quarterly. NextEra expects annual dividend growth of 10% through at least 2024.

Even after the price decline last month, the high-quality stock is not cheap. The dividend yield is below the utility mean. Total return potential is low for the 18-month span and unspectacular for the 3- to 5-year period.

Paul E. Debbas, CFA *May 13, 2022*

(A) Diluted EPS. Excl. nonrecurring gains (losses): '11, (6¢); '13, (20¢); '16, 12¢; '17, 23¢; '18, $1.80; '20, (61¢); '22, (30¢); gain on discontinued ops.: '13, 11¢. Next earnings report due late July. (B) Div'ds historically paid in mid-Mar., mid-June, mid-Sept., & mid-Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '21: $5.94/sh. (D) In mill., adj. for stock split. (E) Rate all'd on com. eq. in '22 (FPL): 9.7%-11.7%; earned on avg. com. eq., '21: 9.7%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	90
Price Growth Persistence	100
Earnings Predictability	55

NORTHWESTERN NDQ-NWE

RECENT PRICE 57.62 | P/E RATIO 17.5 (Trailing: 16.8; Median: 17.0) | RELATIVE P/E RATIO 1.14 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 4 Raised 6/17/22
SAFETY 2 Raised 7/27/18
TECHNICAL 4 Lowered 7/22/22
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$48-$72	$60 (5%)

2025-27 PROJECTIONS

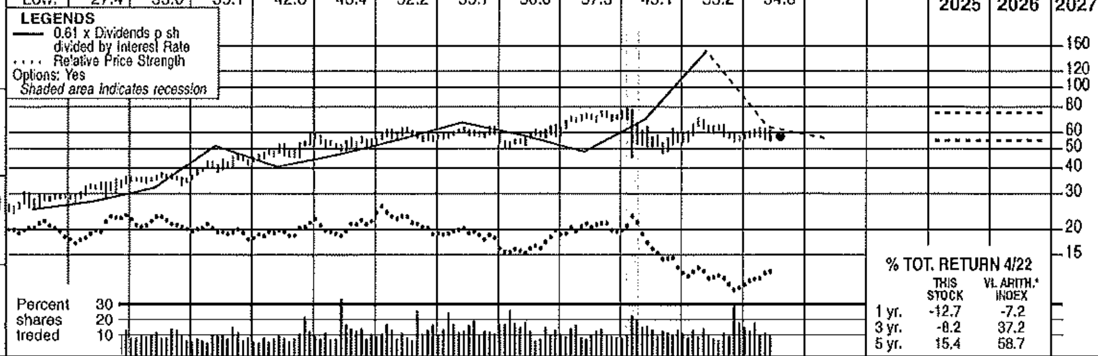
	Price	Gain	Ann'l Total Return
High	75	(+30%)	10%
Low	55	(-5%)	3%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	121	170	154
to Sell	112	105	111
Hld's(000)	49375	56973	57800

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	36.6	38.0	47.2	58.7	59.7	63.8	64.5	65.7	76.7	80.5	70.8	63.1
Low:	27.4	33.0	35.1	42.6	48.4	52.2	55.7	50.0	57.3	45.1	53.2	54.3

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



% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-12.7	-7.2
3 yr.	-8.2	37.2
5 yr.	15.4	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
31.49	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	24.15	23.40	Revenues per sh	25.75
3.62	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	6.72	7.02	6.65	6.70	"Cash Flow" per sh	8.00
1.31	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	3.06	3.60	3.30	3.40	Earnings per sh A	4.00
1.24	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	Div'd Decl'd per sh B ■ †	2.68
2.81	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	10.05	9.10	Cap'l Spending per sh	6.50
20.65	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	44.55	46.15	Book Value per sh C	49.50
35.97	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	58.00	62.00	Common Shs Outst'g D	62.00
26.0	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	19.5	16.9	Bold figures are		Avg Ann'l P/E Ratio	16.5
1.40	1.15	.84	.77	.82	.79	1.00	.95	.85	.93	.90	.90	.91	1.06	1.00	.93	Value Line		Relative P/E Ratio	.90
3.6%	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%	estimates		Avg Ann'l Div'd Yield	4.1%

CAPITAL STRUCTURE as of 3/31/22
Total Debt $2556.2 mill. Due in 5 Yrs $1037.4 mill.
LT Debt $2520.0 mill. LT Interest $87.8 mill.
Incl. $11.9 mill. finance leases.
(LT interest earned: 2.8x)

Pension Assets-12/21 $605.5 mill. Oblig $696.8 mill.

Pfd Stock None

Common Stock 54,138,852 shs. as of 4/22/22

MARKET CAP: $3.1 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
1070.3	1154.5	1204.9	1214.3	1257.2	1305.7	1198.1	1257.9	1198.7	1372.3	1400	1450	Revenues ($mill)	1600
83.7	94.0	120.7	138.4	164.2	162.7	171.1	179.3	155.2	186.8	185	205	Net Profit ($mill)	250
9.6%	13.2%	--	13.7%	--	7.6%	--	1.6%	1.6%	1.8%	1.5%	3.0%	Income Tax Rate	12.0%
9.4%	8.7%	8.9%	9.8%	4.3%	5.2%	3.4%	4.6%	6.3%	14.4%	16.0%	14.0%	AFUDC % to Net Profit	10.0%
53.8%	53.5%	53.4%	53.1%	52.0%	50.2%	52.2%	52.5%	52.8%	52.2%	50.0%	49.5%	Long-Term Debt Ratio	49.0%
46.2%	46.5%	46.6%	46.9%	48.0%	49.8%	47.8%	47.5%	47.2%	47.8%	50.0%	50.5%	Common Equity Ratio	51.0%
2020.7	2215.7	3168.0	3408.6	3493.9	3614.5	4064.6	4289.8	4409.1	4893.1	5190	5660	Total Capital ($mill)	6025
2435.6	2690.1	3758.0	4059.5	4214.9	4358.3	4521.3	4700.9	4952.9	5247.2	5630	5980	Net Plant ($mill)	6550
5.5%	5.5%	4.8%	5.2%	5.9%	5.6%	5.2%	5.2%	4.5%	4.7%	4.5%	4.5%	Return on Total Cap'l	5.0%
9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	8.8%	8.8%	7.5%	8.0%	7.0%	7.0%	Return on Shr. Equity	8.0%
9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	8.8%	8.8%	7.5%	8.0%	7.0%	7.0%	Return on Com Equity E	8.0%
3.2%	3.5%	3.8%	3.0%	4.1%	3.4%	3.2%	3.1%	1.7%	2.5%	1.5%	2.0%	Retained to Com Eq	2.5%
65%	61%	54%	65%	58%	62%	64%	64%	78%	69%	76%	75%	All Div'ds to Net Prof	67%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+4.6	-4.4	+.7
Avg. Indust. Use (MWH)	37808	33526	31792
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	2237	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+1.2	+1.6
Fixed Charge Cov. (%)	284	237	252

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.5%	-1.0%	.5%
"Cash Flow"	3.5%	3.0%	2.5%
Earnings	4.5%	2.0%	3.0%
Dividends	5.5%	5.5%	2.0%
Book Value	6.0%	4.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	384.2	270.7	274.8	328.2	1257.9
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	310	335	360.5	1400
2023	410	320	345	375	1450

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.44	.49	.42	1.18	3.53
2020	1.00	.43	.58	1.06	3.06
2021	1.24	.72	.68	.96	3.60
2022	1.08	.55	.60	1.07	3.30
2023	1.12	.57	.62	1.09	3.40

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.55	.55	.55	.55	2.20
2019	.575	.575	.575	.575	2.30
2020	.60	.60	.60	.60	2.40
2021	.62	.62	.62	.62	2.48
2022	.63	.63			

BUSINESS: NorthWestern Corporation (doing business as NorthWestern Energy) supplies electricity & gas in the Upper Midwest and Northwest, serving 456,000 electric customers in Montana and South Dakota and 298,000 gas customers in Montana (85% of gross margin), South Dakota (14%), and Nebraska (1%). Electric revenue breakdown: residential, 43%; commercial, 49%; industrial, 4%; other, 4%. Generating sources: coal, 28%; hydro, 27%; wind, 6%; other, 4%; purchased, 35%. Fuel costs: 31% of revenues. '21 reported deprec. rate: 2.8%. Has 1,500 employees. Chairman: Dana J. Dykhouse. CEO: Robert C. Rowe. President & COO: Brian B. Bird. Inc.: DE. Address: 3010 West 69th Street, Sioux Falls, SD 57108. Tel.: 605-978-2900. Internet: www.northwesternenergy.com.

NorthWestern's share earnings have flatlined for years, as has the stock. The issue has consolidated around the $60 price level going all the way back to 2016. That was the last year to see a sizable gain in EPS from operations. While net profits have grown gradually over the past five years (the average rate was 2.5%-3%), shares outstanding have also risen, diluting per-share gains. The main constraint, besides dilution, has been years of underearning the utility's allowable return on equity (ROE). (See "Return of Common Equity" in the financial projections array and footnote E.) This is due to the relative constraints of the rate-relief mechanisms available in the company's regulatory territories. We expect flat share earnings to persist through 2023.

Leadership has an ambitious plan in place it believes will help reignite the company's bottom-line growth. In an effort to become less reliant on purchased power, while modernizing and shoring up reliability, the company is looking to add significant gas-fired capacity in both South Dakota and Montana. An $80 million, 58-megawatt plant in South Dakota was nearing completion in the second quarter with another 35-mw operation slated by early 2024. NWE also plans to build a $275 million, 175-mw facility in Montana, but litigation has been filed challenging the air-quality permit. Financing is via a $200 million equity offering ($53.50 a share) done in fourth quarter 2021, with $300 million more expected to take place by early 2023 through a forward sale.

The desired results will depend on favorable rate cases, difficult to come by in a tough regulatory territory. NWE plans to file a rate case in Montana this summer, and is looking to obtain some rate relief next year. If the expansions are allowed to proceed, this should lift the rate base and enable the company to narrow the gap between its earned and allowable ROE. Yet, it's not a given NWE will get all project costs included in its rate base.

We wouldn't sacrifice growth for untimely NWE's high dividend yield. While it is 90 basis points above the utility average, dividend growth is constrained by the high payout ratio. And equity sales should cap near-term appreciation.

Anthony J. Glennon *July 22, 2022*

(A) Diluted EPS. Excl. nonrec. gains: '12, 39¢; '15, 27¢; '18, 52¢; '19, 45¢. '20 EPS don't sum due to rounding. Next earnings report due late August. (B) Div'ds historically paid in late Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. def'd charges. In '21: $19.39/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%; earned on avg. com. eq., '21: 8.5%. Regulatory Climate: Below Average.

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

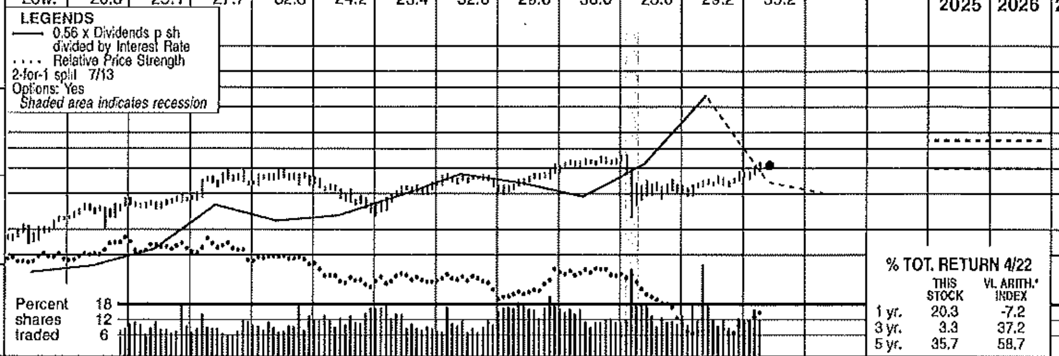
OGE ENERGY CORP. NYSE-OGE

RECENT PRICE 41.48 | P/E RATIO 16.3 (Trailing: 17.1; Median: 17.0) | RELATIVE P/E RATIO 0.98 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Raised 5/20/22
SAFETY 2 Lowered 12/18/15
TECHNICAL 2 Lowered 6/3/22
BETA 1.00 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	28.6	30.1	40.0	39.3	36.5	34.2	37.4	41.8	45.8	46.4	38.6	42.7
Low:	20.3	25.1	27.7	32.8	24.2	23.4	32.6	29.6	38.0	23.0	29.2	35.2

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range

Low-High: $34-$50 | Midpoint (% to Mid): $42 (0%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+35%)	11%
Low	40	(-5%)	4%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	188	230	228
to Sell	157	150	170
Hld's(000)	126167	128749	129869

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.3	-7.2
3 yr.	3.3	37.2
5 yr.	35.7	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
21.96	20.68	21.77	14.79	19.04	19.96	18.58	14.45	12.30	11.00	11.31	11.32	11.37	11.15	10.61	18.26	*14.00*	*15.00*	Revenues per sh	*18.25*
2.23	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	*4.75*	*5.05*	"Cash Flow" per sh	*6.25*
1.23	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	*2.55*	*2.70*	Earnings per sh A	*3.25*
.67	.68	.70	.71	.73	.76	.80	.85	.95	1.05	1.16	1.27	1.40	1.51	1.58	1.63	*1.66*	*1.70*	Div'd Decl'd per sh B ■	*1.85*
2.67	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	3.69	*4.75*	*4.75*	Cap'l Spending per sh	*4.75*
8.79	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	*22.20*	*23.25*	Book Value per sh C	*27.00*
182.40	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	*200.10*	*200.10*	Common Shs Outst'g D	*200.10*
13.7	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	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*14.0*
.74	.73	.75	.72	.85	.90	.97	.99	.96	.89	.93	.92	.89	1.01	.83	.76	*estimates*		Relative P/E Ratio	*.80*
4.0%	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%			Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $5228.5 mill. Due in 5 Yrs $1731.5 mill.
LT Debt $4497.0 mill. LT Interest $158.7 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $5.7 mill.

Pension Assets-12/21 $486.0 mill. Oblig $502.9 mill.

Pfd Stock None

Common Stock 200,202,672 shs.

MARKET CAP: $8.3 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
3671.2	2867.7	2453.1	2196.9	2259.2	2261.1	2270.3	2231.6	2122.3	3653.7	*2800*	*3000*	Revenues ($mill)	*3650*
355.0	387.6	395.8	337.6	338.2	384.3	425.5	449.6	415.9	472.5	*510*	*545*	Net Profit ($mill)	*675*
26.0%	24.9%	30.4%	29.2%	30.5%	32.5%	14.5%	7.4%	13.2%	11.5%	*12.0%*	*12.0%*	Income Tax Rate	*12.0%*
2.7%	2.6%	1.7%	3.7%	6.4%	15.0%	8.3%	1.6%	1.6%	2.2%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
50.7%	43.1%	45.9%	44.3%	41.1%	41.7%	42.0%	43.6%	49.0%	52.6%	*46.0%*	*51.5%*	Long-Term Debt Ratio	*49.0%*
49.3%	56.9%	54.1%	55.7%	58.9%	58.3%	58.0%	56.4%	51.0%	47.4%	*54.0%*	*48.5%*	Common Equity Ratio	*51.0%*
5615.8	5337.2	5999.7	5971.6	5849.6	6600.7	6902.0	7334.7	7126.2	8552.7	*8240*	*9595*	Total Capital ($mill)	*10650*
8344.8	6672.8	6979.9	7322.4	7696.2	8339.9	8643.8	9044.6	9374.6	9832.9	*10345*	*10830*	Net Plant ($mill)	*12075*
7.7%	8.6%	7.8%	6.9%	7.0%	7.0%	7.3%	7.1%	6.9%	6.4%	*7.0%*	*6.5%*	Return on Total Cap'l	*7.5%*
12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	11.6%	*11.5%*	*11.5%*	Return on Shr. Equity	*12.5%*
12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	11.6%	*11.5%*	*11.5%*	Return on Com Equity E	*12.5%*
7.2%	7.3%	6.5%	4.0%	3.3%	3.5%	3.8%	3.6%	2.8%	3.6%	*4.0%*	*4.5%*	Retained to Com Eq	*5.5%*
44%	43%	47%	61%	67%	64%	64%	67%	76%	69%	*65%*	*62%*	All Div'ds to Net Prof	*55%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+1.1	-4.9	+2.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.69	4.40	7.68
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6817	6437	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+1.1	+1.4
Fixed Charge Cov. (%)	335	326	336

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-3.0%	3.0%	5.5%
"Cash Flow"	3.5%	4.5%	7.0%
Earnings	4.0%	4.5%	6.5%
Dividends	8.0%	8.5%	3.0%
Book Value	5.5%	3.5%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	490.0	513.7	755.4	472.5	2231.6
2020	431.3	503.5	702.1	485.4	2122.3
2021	1630.6	577.4	864.4	581.3	3653.7
2022	589.3	*650*	*910.7*	*650*	*2800*
2023	*650*	*700*	*950*	*700*	*3000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.24	.50	1.25	.26	2.24
2020	.23	.51	1.04	.30	2.08
2021	.26	.56	1.26	.27	2.36
2022	.33	*.60*	*1.32*	*.30*	*2.55*
2023	*.32*	*.65*	*1.40*	*.33*	*2.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.3325	.3325	.3325	.365	1.36
2019	.365	.365	.365	.388	1.48
2020	.3875	.3875	.3875	.4025	1.57
2021	.4025	.4025	.4025	.41	1.62
2022	.41	.41			

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 878,000 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. '21 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 is awaiting a rate order in Oklahoma. Oklahoma Gas and Electric is seeking an increase of $164 million, based on a 10.2% return on equity and a 53.4% common-equity ratio. The utility needs to recover capital investment made since its last rate case, three years ago. OG&E also requested a performance-based ratemaking mechanism. The staff of the Oklahoma Corporation Commission recommended an increase of $83 million, based on an 8.75% ROE, and the attorney general proposed a slight decrease, based on a 9.5% ROE. OG&E will try to settle the case, and may implement interim rates if an order has not been received by July 1st.

The utility received rate relief in Arkansas. A $4.2 million increase under the state's formula rate plan took effect on April 1st. The formula rate plan has been extended for five years.

We look for steady earnings growth in 2022 and 2023. Rate relief in Oklahoma and Arkansas should be the key factor. The service area's economy is healthy.

OGE Energy is exiting its midstream gas investment. As of March 31st, its interest in Energy Transfer was on the hooks for more than $1 billion, following an unrealized gain that boosted earnings by $1.06 a share in the first quarter. We *excluded* this from our earnings presentation as a nonrecurring item. Through the end of April, the company had sold 21.75 million units for $246 million (pretax), and expects to sell most of its units by yearend. OGE Energy plans to use the sale proceeds to reduce short-term debt and fund its capital budget. If the units retain their value through the duration of the sale process, this will provide cash of more than $600 million after taxes.

OG&E plans to issue securitized bonds to recover the surge in gas and power costs that occurred in February of 2021. The sharp rise in fuel costs explains why revenues were unusually high in the first quarter last year. This will amount to as much as $760 million.

This stock has an attractive dividend yield. The yield is well above the utility average. The drawback is the subpar dividend growth potential, as a result of the high payout ratio.

Paul E. Debbas, CFA *June 10, 2022*

(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.: '06, 20¢. '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 '21: $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	25
Earnings Predictability	95

OTTER TAIL CORP. NDQ-OTTR

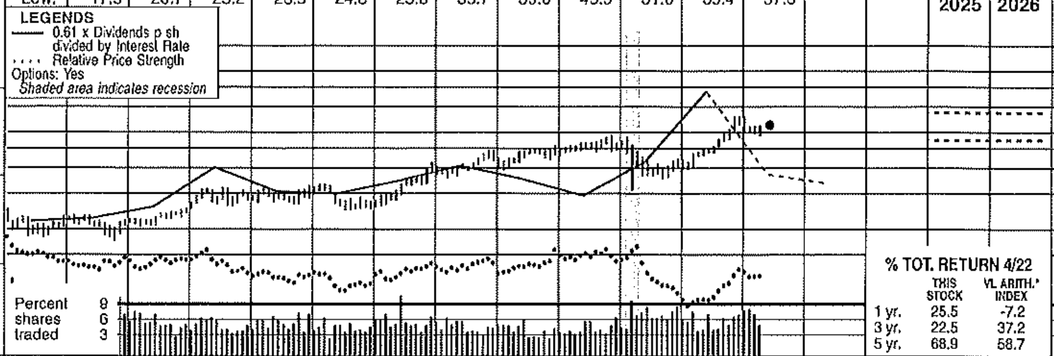
RECENT PRICE 65.37 | P/E RATIO 12.3 (Trailing: 12.5; Median: 20.0) | RELATIVE P/E RATIO 0.74 | DIV'D YLD 2.6% | VALUE LINE

TIMELINESS 1 Raised 6/3/22
SAFETY 2 Raised 6/17/16
TECHNICAL 3 Lowered 6/3/22
BETA .85 (1.00 = Market)

High:	23.5	25.3	31.9	32.7	33.4	42.6	48.7	51.9	57.7	56.9	71.7	71.9
Low:	17.5	20.7	25.2	26.5	24.8	25.8	35.7	39.0	45.9	31.0	39.4	57.6

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

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$56-$92 $74 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+15%)	6%
Low	55	(-15%)	-1%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	94	112	121
to Sell	66	84	87
Hld's(000)	19727	19393	19574

Percent shares traded 9 6 3

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	25.5	-7.2
3 yr.	22.5	37.2
5 yr.	68.9	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
37.43	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	*32.80*	*28.90*	Revenues per sh	*32.25*
3.39	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	*7.65*	*6.45*	"Cash Flow" per sh	*6.75*
1.69	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	*5.30*	*4.00*	Earnings per sh A	*3.75*
1.15	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*	*1.76*	Div'd Decl'd per sh B ■	*2.20*
2.35	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	*4.35*	*5.90*	Cap'l Spending per sh	*6.25*
16.67	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	*27.55*	*29.80*	Book Value per sh C	*34.25*
29.52	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	*41.75*	*41.90*	Common Shs Outst'g D	*42.50*
17.3	19.0	30.1	31.2	NMF	NMF	21.7	21.1	18.8	18.2	20.2	22.1	22.2	23.5	18.3	12.3	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
.93	1.01	1.81	2.08	NMF	NMF	1.38	1.19	.99	.92	1.06	1.11	1.20	1.25	.94	.66	*Value Line*		Relative P/E Ratio	*.95*
3.9%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $861.8 mill. Due in 5 Yrs $207.8 mill.
LT Debt $734.1 mill. LT Interest $31.6 mill.
(LT Interest earned: 9.7x)

Leases, Uncapitalized Annual rentals $5.0 mill.
Pension Assets-12/21 $387.2 mill. Oblig $416.7 mill.

Pfd Stock None

Common Stock 41,630,655 shs. as of 4/27/22

MARKET CAP: $2.7 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
859.2	893.3	799.3	779.8	803.5	849.4	916.4	919.5	890.1	1196.8	*1370*	*1210*	Revenues ($mill)	*1370*
39.0	50.2	56.9	58.6	62.0	73.9	82.3	86.8	95.9	176.8	*225*	*170*	Net Profit ($mill)	*165*
5.2%	21.3%	22.5%	27.0%	24.5%	25.5%	15.0%	16.7%	17.4%	16.9%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
1.7%	5.6%	3.9%	3.5%	2.2%	2.3%	4.1%	4.9%	6.4%	.8%	*1.0%*	*3.0%*	AFUDC % to Net Profit	*4.0%*
44.0%	42.1%	46.5%	42.4%	43.0%	41.3%	44.7%	46.9%	41.8%	42.6%	*41.5%*	*41.5%*	Long-Term Debt Ratio	*42.5%*
54.4%	57.9%	53.5%	57.6%	57.0%	58.7%	55.3%	53.1%	58.2%	57.4%	*58.5%*	*58.5%*	Common Equity Ratio	*57.5%*
959.2	924.4	1071.3	1051.0	1175.4	1187.3	1318.9	1471.1	1495.4	1724.8	*1975*	*2140*	Total Capital ($mill)	*2525*
1049.5	1167.0	1268.5	1387.8	1477.2	1539.6	1581.1	1753.8	2049.3	2124.6	*2210*	*2355*	Net Plant ($mill)	*2700*
5.7%	6.8%	6.7%	6.8%	6.5%	7.3%	7.3%	7.0%	7.4%	11.1%	*12.0%*	*9.0%*	Return on Total Cap'l	*7.5%*
7.3%	9.4%	9.9%	9.7%	9.3%	10.6%	11.3%	11.1%	11.0%	17.8%	*19.5%*	*13.5%*	Return on Shr. Equity E	*11.5%*
7.3%	9.3%	9.9%	9.7%	9.3%	10.6%	11.3%	11.1%	11.0%	17.8%	*19.5%*	*13.5%*	Return on Com Equity	*11.5%*
NMF	1.2%	2.2%	2.0%	2.1%	3.3%	4.0%	4.0%	4.1%	11.3%	*13.5%*	*7.5%*	Retained to Com Eq	*5.0%*
113%	87%	78%	79%	78%	69%	65%	64%	63%	37%	*31%*	*44%*	All Div'ds to Net Prof	*57%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-.2	-3.9	+.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, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.1	NA	NA
Fixed Charge Cov. (%)	407	405	651

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.0%	3.0%	*5.0%*
"Cash Flow"	7.0%	9.0%	*5.5%*
Earnings	19.0%	13.0%	*4.5%*
Dividends	2.0%	4.0%	*7.0%*
Book Value	2.0%	6.0%	*8.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	246.0	229.2	228.6	215.7	919.5
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	*380.1*	*310*	*305*	*1370*
2023	*310*	*305*	*300*	*295*	*1210*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.66	.39	.62	.51	2.17
2020	.60	.42	.87	.45	2.34
2021	.73	1.01	1.26	1.23	4.23
2022	1.72	*1.68*	*1.10*	*.80*	*5.30*
2023	*1.25*	*1.10*	*.90*	*.75*	*4.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.335	.335	.335	.335	1.34
2019	.35	.35	.35	.35	1.40
2020	.37	.37	.37	.37	1.48
2021	.39	.39	.39	.39	1.56
2022	.4125	.4125			

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 (62% of '21 operating income). '21 deprec. rate: 2.9%. 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.

Otter Tail Corporation's results continue to benefit from what management describes as "unique supply and demand market conditions" experienced by its Plastics division. This is why earnings surged in 2021. The company had expected these conditions to return to normal sometime in 2022, which is why we estimated an earnings decline (to $3.95 a share) in our March report. However, the rise in prices of the PVC pipe that the company builds has soared even more than the cost of manufacturing it, thereby lifting Otter Tail's profitability materially. Management had expected to see a price decline in the quarter.

The company raised its earnings guidance for 2022 upon reporting first-quarter results in early May. Otter Tail's previous targeted range was $3.78-$4.08 a share. Its revised guidance is $5.15-$5.45. We raised our estimate from $3.95 to $5.30. Management stated that it expects to see elevated earnings from its Plastics operation into 2023. Accordingly, we raised our estimate for next year from $2.90 a share to $4.00. Although this would be a sharp decline from the estimated 2022 tally, it would still be well above Otter Tail's profits prior to 2021.

Otter Tail Power has some projects in various stages of development. A 49-megawatt solar facility is expected to be completed in 2023 at a cost of approximately $60 million. All major contracts are in place, so supply-chain problems that are affecting the solar business shouldn't be a problem. The utility is spending about $145 million through 2024 to install advanced meters and modernize its electric grid. Otter Tail wants to exercise its option to buy a 62-mw wind farm at a cost of $50 million. This is expected to close in early 2023. The cost of these investments will be recovered through general rate cases or riders (surcharges) on customers' bills in Minnesota.

After a stellar showing in 2021, the price of this timely stock has retreated 9% this year. This is understandable after the quotation soared 68% last year, thanks to earnings that far exceeded Otter Tail's initial guidance. Total return potential is below the median for the next 18 months and low for 2025-2027.

Paul E. Debbas, CFA *June 10, 2022*

(A) Dil. EPS. Excl. nonrec. gains (loss): '10, (44¢); '11, 26¢; '13, 2¢; gains (losses) from disc. ops.: '06, 1¢; '11, ($1.11); '12, ($1.22); '13, 2¢; '14, 2¢; '15, 2¢; '16, 1¢; '17, 1¢. '19 EPS don't 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 '21: $4.14/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%. Regul. Climate: MN, ND, Avg.; SD, Above Avg.

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

PINNACLE WEST NYSE-PNW

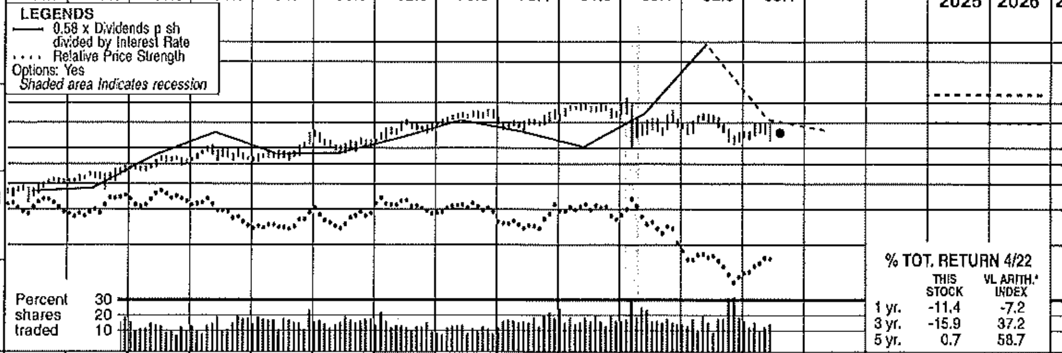
RECENT PRICE 71.47 | P/E RATIO 17.9 (Trailing: 13.5; Median: 17.0) | RELATIVE P/E RATIO 1.16 | DIV'D YLD 4.8% | VALUE LINE

TIMELINESS 4 Raised 6/10/22
SAFETY 2 Lowered 10/22/21
TECHNICAL 3 Raised 7/1/22
BETA .90 (1.00 = Market)

High:	48.9	54.7	61.9	71.1	73.3	82.8	92.5	92.6	99.8	105.5	88.5	80.5
Low:	37.3	45.9	51.5	51.2	56.0	62.5	75.8	73.4	81.6	60.1	62.6	65.1

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

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$53-$90 $72 (0%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	110	(+55%)	15%
Low	80	(+10%)	8%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	247	228	252
to Sell	214	265	212
Hld's(000)	94972	90979	95123

Percent shares traded 30 20 10

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-11.4	-7.2
3 yr.	-15.9	37.2
5 yr.	0.7	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
34.03	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	*35.40*	*36.75*	Revenues per sh	*39.00*
9.70	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	*11.10*	*11.70*	"Cash Flow" per sh	*13.75*
3.17	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	*4.00*	*4.25*	Earnings per sh A	*5.25*
2.03	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	*3.44*	*3.52*	Div'd Decl'd per sh B ■	*3.76*
7.59	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	*14.10*	*14.10*	Cap'l Spending per sh	*14.50*
34.48	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	*52.85*	*53.60*	Book Value per sh C	*58.50*
99.96	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	*113.00*	*113.00*	Common Shs Outst'g D	*118.00*
13.7	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	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.74	.79	.97	.91	.80	.92	.91	.86	.84	.81	.98	.97	.96	1.03	.86	.77	*Value Line*		Relative P/E Ratio	*1.00*
4.7%	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%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $7489.6 mill. Due in 5 Yrs $1892.0 mill.
LT Debt $7226.6 mill. LT Interest $244.1 mill.
(LT interest earned: 3.7x)

Leases, Uncapitalized Annual rentals $13.1 mill.

Pension Assets-12/21 $3812.0 mill.
Oblig $3716.8 mill.

Pfd Stock None

Common Stock 113,001,085 shs.
as of 4/28/22
MARKET CAP: $8.1 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
3301.8	3454.6	3491.6	3495.4	3498.7	3565.3	3691.2	3471.2	3587.0	3803.8	*4000*	*4150*	Revenues ($mill)	*4600*
387.4	406.1	397.6	437.3	442.0	497.8	511.0	538.3	550.6	618.7	*455*	*480*	Net Profit ($mill)	*620*
36.2%	34.4%	34.2%	34.3%	33.9%	32.5%	20.2%	--	12.1%	14.8%	*13.5%*	*13.5%*	Income Tax Rate	*13.5%*
9.7%	10.0%	11.6%	11.8%	14.1%	13.9%	15.2%	9.3%	9.5%	10.1%	*14.0%*	*13.0%*	AFUDC % to Net Profit	*11.0%*
44.6%	40.0%	41.0%	43.0%	45.6%	48.9%	47.0%	47.1%	52.8%	53.9%	*55.0%*	*55.0%*	Long-Term Debt Ratio	*55.0%*
55.4%	60.0%	59.0%	57.0%	54.4%	51.1%	53.0%	52.9%	47.2%	46.1%	*45.0%*	*45.0%*	Common Equity Ratio	*45.0%*
7171.9	6990.9	7398.7	8046.3	8825.4	9796.4	9861.1	10263	11948	12820	*13275*	*13400*	Total Capital ($mill)	*15325*
10396	10889	11194	11809	12714	13445	14030	14523	15159	15987	*16775*	*17525*	Net Plant ($mill)	*19875*
6.8%	7.1%	6.4%	6.4%	6.0%	6.1%	6.2%	6.3%	5.5%	5.8%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.0%*
9.8%	9.7%	9.1%	9.5%	9.2%	9.9%	9.8%	9.9%	9.8%	10.5%	*7.5%*	*8.0%*	Return on Shr. Equity	*9.0%*
9.8%	9.7%	9.1%	9.5%	9.2%	9.9%	9.8%	9.9%	9.8%	10.5%	*7.5%*	*8.0%*	Return on Com Equity E	*9.0%*
4.1%	4.1%	3.5%	3.9%	3.5%	4.2%	3.9%	3.8%	3.5%	4.2%	*1.0%*	*1.5%*	Retained to Com Eq	*2.5%*
58%	58%	62%	59%	62%	58%	60%	61%	64%	60%	*86%*	*83%*	All Div'ds to Net Prof	*71%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-.4	+5.4	+2.8
Avg. Indust. Use (MWH)	714	583	808
Avg. Indust. Revs. per KWH (¢)	7.88	7.49	8.11
Capacity at Peak (Mw)	8241	9094	8726
Peak Load, Summer (Mw)	7115	7660	7580
Annual Load Factor (%)	47.1	45.5	45.9
% Change Customers (yr-end)	+2.0	+2.1	+2.2
Fixed Charge Cov. (%)	286	318	317

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	.5%	*3.5%*
"Cash Flow"	4.5%	5.0%	*3.0%*
Earnings	6.0%	5.5%	*.5%*
Dividends	4.5%	5.5%	*2.5%*
Book Value	4.0%	4.0%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	740.5	869.5	1190.8	670.4	3471.2
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*	*1035*	*1350*	*831.5*	*4000*
2023	*810*	*1075*	*1400*	*865*	*4150*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.16	1.28	2.77	.57	4.77
2020	.27	1.71	3.07	d.17	4.87
2021	.32	1.91	3.00	.24	5.47
2022	.15	*1.35*	*2.30*	*.20*	*4.00*
2023	*.20*	*1.40*	*2.40*	*.25*	*4.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.695	.695	.695	.737	2.82
2019	.737	.738	.738	.782	3.00
2020	.783	.783	.783	.83	3.18
2021	.83	.83	.83	.85	3.34
2022	.85	.85			

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, 51%; commercial, 38%; industrial, 5%; other, 6%. Generating sources: gas & other, 30%; nuclear, 27%; coal, 20%; purchased, 23%. Fuel costs: 30% of revenues. '21 reported deprec. rate: 2.9%. Has 5,900 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.

Untimely Pinnacle West stock is still seeking its equilibrium level after the regulatory blow the company suffered last year. From mid-2021, it became apparent that the company's utility (APS) wasn't going to get the rate relief it was seeking from its regulatory agency (ACC). APS and ACC staff were far apart on the size of their proposed increases, and the state's residential consumer office was seeking a large cut. When the rate decision arrived in November, Pinnacle West saw its allowed return on equity (ROE) reduced from 10% to 8.7% (one of the lowest in the U.S.), and its annual earning power cut by $0.90 a share. PNW stock fell 30% (May to November) before exhibiting an impressive relief rally into April, finally giving much of that back with the broad market decline and the realization that restitution may be unlikely.

The utility has thus far been unsuccessful in its bid for a judiciary appeal. In December, APS filed a petition for special action with the Arizona Supreme Court, but was turned down. It also put in a request to argue its case before the state Court of Appeals but has had no response.

Yet, from this year's impaired bottom line, there is good recovery potential out to mid-decade and beyond. We aren't assuming any near-term rate relief although APS will likely re-file before year's end. The utility should benefit from solid kilowatt-hour sales growth. APS expects annual retail volume gains of 1.5%-2.5%, driven by its growing customer base. Longer term, the company is assuming 3.5%-4.5% retail sales growth with the electrification of the transportation system a contributing factor. Renewable projects to support that growth almost assuredly have to enter the rate base. Projecting forward from this year's depressed level, 7% annual share-earnings gains are feasible.

PNW offers a dividend yield 130 basis points above its industry average, but payout growth may be subpar to mid-decade. The impairment to earnings caused a sharp rise to the payout ratio. Thus, the board raised the dividend just 2.4% in late 2021 as compared to the previous 6% hike. Utility investors with a very long horizon may find the high yield plus recovery potential appealing.

Anthony J. Glennon *July 22, 2022*

(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 earnings report due Aug 3rd. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '21: $23.60/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '21: 8.7%; earned on avg. com. eq., '21: 10.7%. Regulatory Climate: Below Avg.

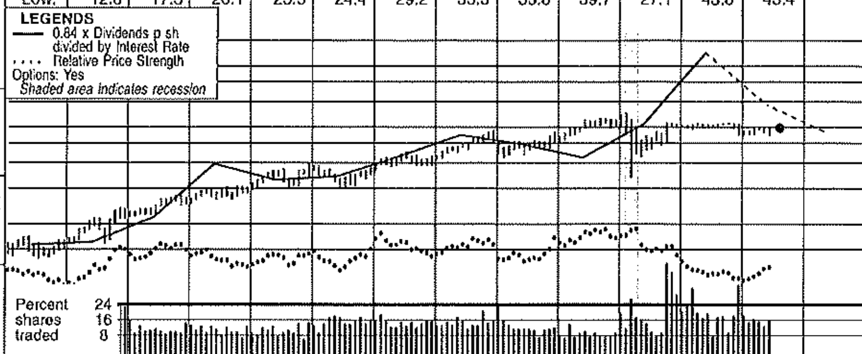
Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	45
Earnings Predictability	95

PNM RESOURCES NYSE-PNM

RECENT PRICE 47.57 | P/E RATIO 18.7 (Trailing: 18.5 / Median: 20.0) | RELATIVE P/E RATIO 1.21 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 2 Raised 7/1/22
SAFETY 2 Raised 4/23/21
TECHNICAL 3 Raised 5/20/22
BETA .95 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	19.2	22.5	24.5	31.6	31.2	36.2	46.0	45.3	53.0	56.1	50.1	48.7
Low:	12.8	17.3	20.1	23.5	24.4	29.2	33.3	33.8	39.7	27.1	43.8	43.4



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$44-$58	$51 (5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+35%)	10%
Low	50	(+5%)	4%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	110	145	139
to Sell	123	116	107
Hld's(000)	72629	74354	78937

Target Price Range 2025 | 2026 | 2027

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-3.6	-7.2
3 yr.	8.0	37.2
5 yr.	40.9	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
32.25	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	21.30	21.10	Revenues per sh	23.25
3.57	2.54	1.76	2.32	2.67	3.18	3.39	3.52	4.09	4.28	4.51	5.30	5.13	6.07	5.68	6.01	6.45	6.60	"Cash Flow" per sh	8.00
1.72	.76	.11	.58	.87	1.08	1.31	1.41	1.45	1.48	1.46	1.92	1.66	2.28	2.15	2.27	2.55	2.65	Earnings per sh A	3.00
.86	.91	.61	.50	.50	.50	.58	.68	.76	.82	.90	.99	1.09	1.18	1.25	1.33	1.41	1.49	Div'd Decl'd per sh B ■ †	1.80
4.04	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	10.20	10.55	Cap'l Spending per sh	9.00
22.09	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	26.90	28.45	Book Value per sh C	32.00
76.65	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	88.00	90.00	Common Shs Outst'g D	90.00
15.6	35.6	NMF	18.1	14.0	14.5	15.0	16.1	18.7	18.7	22.4	20.4	23.4	21.1	20.8	21.5	Bold figures are		Avg Ann'l P/E Ratio	19.5
.84	1.89	NMF	1.21	.89	.91	.95	.90	.98	.94	1.18	1.03	1.26	1.12	1.07	1.16	Value Line		Relative P/E Ratio	1.10
3.2%	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%	estimates		Avg Ann'l Div'd Yield	3.1%
						1342.4	1387.9	1435.9	1439.1	1363.0	1445.0	1436.6	1457.6	1523.0	1779.9	1875	1900	Revenues ($mill)	2100
						106.1	114.0	116.8	118.8	117.4	154.4	133.4	182.8	173.3	196.4	225	235	Net Profit ($mill)	275
						31.4%	31.6%	34.8%	36.9%	32.4%	33.0%	13.8%	9.4%	9.9%	13.3%	21.0%	21.0%	Income Tax Rate	21.0%
						7.1%	1.3%	10.7%	17.0%	11.0%	11.9%	14.5%	9.2%	9.4%	9.3%	9.0%	8.0%	AFUDC % to Net Profit	7.0%
						50.9%	50.0%	47.8%	54.1%	55.7%	56.1%	61.1%	59.8%	56.9%	61.8%	60.0%	59.0%	Long-Term Debt Ratio	60.0%
						48.7%	49.7%	51.9%	45.5%	44.0%	43.6%	38.6%	39.9%	42.9%	38.0%	39.5%	41.0%	Common Equity Ratio	40.0%
						3277.9	3344.0	3437.1	3633.3	3806.8	3887.5	4370.0	4207.7	4780.6	5698.6	5975	6270	Total Capital ($mill)	7175
						3746.5	3933.9	4270.0	4535.4	4904.7	4980.2	5234.6	5466.0	5965.1	6752.9	7305	7895	Net Plant ($mill)	9050
						5.1%	5.2%	5.1%	4.8%	4.7%	5.3%	4.3%	5.8%	4.7%	4.3%	4.5%	4.5%	Return on Total Cap'l	4.5%
						6.6%	6.8%	6.5%	7.1%	7.0%	9.0%	7.8%	10.8%	8.4%	9.0%	9.5%	9.0%	Return on Shr. Equity	9.5%
						6.6%	6.8%	6.5%	7.1%	7.0%	9.1%	7.9%	10.9%	8.4%	9.0%	9.5%	9.0%	Return on Com Equity E	9.5%
						3.8%	3.8%	3.2%	3.3%	2.8%	4.5%	2.9%	5.4%	3.6%	3.8%	4.0%	4.0%	Retained to Com Eq	4.0%
						43%	45%	51%	54%	61%	51%	64%	51%	57%	58%	55%	56%	All Div'ds to Net Prof	60%

CAPITAL STRUCTURE as of 3/31/22
Total Debt $3885.5 mill. Due in 5 Yrs $2046.4 mill.
LT Debt $3620.0 mill. LT Interest $92.6 mill.
(LT interest earned: 3.3x)
Leases, Uncapitalized Annual rentals $28.4 mill.
Pension Assets-12/21 $639.6 mill. Oblig $643.7 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 4/21/22
MARKET CAP: $4.1 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+5.0	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	2761	NA	NA
Peak Load, Summer (Mw)	1937	1974	1968
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	228	237	299

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-0.5%	1.5%	3.5%
"Cash Flow"	8.0%	6.5%	5.0%
Earnings	10.0%	9.0%	5.0%
Dividends	9.5%	8.5%	6.0%
Book Value	2.5%	2.0%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	349.7	330.2	433.6	344.1	1457.6
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	430.9	560	440	1875
2023	445	440	570	445	1900

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.23	.36	1.29	.40	2.28
2020	d.19	.72	1.52	.10	2.15
2021	.20	.62	1.32	.13	2.27
2022	.50	.50	1.30	.25	2.55
2023	.52	.52	1.34	.27	2.65

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.265	.265	.265	.265	1.06
2019	.29	.29	.29	.29	1.16
2020	.3075	.3075	.3075	.3075	1.23
2021	.3275	.3275	.3275	.3275	1.31
2022	.3475	.3475			

BUSINESS: PNM Resources, Inc. is a holding company with two regulated electric utilities. Public Service Company of New Mexico (PNM) serves 538,000 customers in north central New Mexico, including Albuquerque and Santa Fe. Texas-New Mexico Power Company (TNMP) transmits and distributes power to 261,000 customers in Texas. Electric revenue breakdown: residential, 42%; commercial, 36%; industrial, 8%; other, 14%. Generating sources not available. Fuel costs: 36% of revenues. '21 reported depreciation rates: 2.5%-7.9%. Has 1,600 employees. Chairman, President & CEO: Patricia K. Collawn. Incorporated: New Mexico. Address: 414 Silver Ave. SW, Albuquerque, New Mexico 87102-3289. Telephone: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources' regulators recently ordered it to issue substantial rate credits to its customer base. The New Mexico Public Regulation Commission (NMPRC) is ordering rate credits related to the retirement of the San Juan coal plant's two remaining generating units, resulting in a $128 million pretax, nonrecurring charge over the next two years if the decision stands. PNM argues that the action from the regulators is in direct violation of the state's Energy Transition Act and is unfairly penalizing PNM for its decision to exit coal generation.

This is the same agency that has thus far stood in the way of the company's acquisition agreement with Northeast utility AVANGRID, Inc (AGR). In regard to the merger agreement, the deal calls for PNM stockholders to receive $50.30 in cash per share. The deal needed the approval of a number of state and federal regulatory agencies and recieved concent from all but this one. Last December, NMPRC rejected the merger citing concerns over AGR's track record in the Northeast, a legal investigation into the CEO of its parent company, Iberdrola (based in Spain), and potentially rising electricity prices. Charges against the CEO have since been dropped in Spain.

But for now, PNM's only recourse in these instances is to make its case via judicial appeals. In February, the two companies appealed NMPRC's denial to the state Supreme Court. Since then, NMPRC complained that Iberdrola hired an attorney with close ties to the New Mexico attorney general. This point has since been refuted by the Supreme Court Disciplinary Board. The full process is expected to take no less than 12-18 months.

We think the AVANGRID deal eventually gets done, but shareholders need to decide if it's worth the wait. Timely PNM's dividend is well covered and growing. Despite a poor regulatory environment in New Mexico, the Texas territory is solid and should keep overall profits on the rise. So, as an ongoing concern, long-term prospects are worthwhile. Including dividends, we calculate an 11.1% return (7.2% annualized) over an 18-month time horizon, plus or minus six months, to merger's completion.

Anthony J. Glennon *July 22, 2022*

(A) Dil. EPS. Excl. nonrec. gain (loss): '08, ($3.77); '10, ($1.36); '11, 88¢; '13, (16¢); '15, ($1.28); '17, (92¢); '18, (59¢); '19, ($1.31); '22, (31¢). Excl. disc. op. gains: '08, 42¢; '09, 78¢. Next egs. report due early Aug. (B) Div'ds paid mid-Feb., May, Aug., & Nov. ■ Div'd reinv. plan avail. (C) Incl. intang. In '21: $10.86/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%; earned on avg. com. eq., '21: 9.3%. Reg. Climate: NM, Below Avg.; TX, Avg.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	75
Earnings Predictability	80

PORTLAND GENERAL NYSE-POR

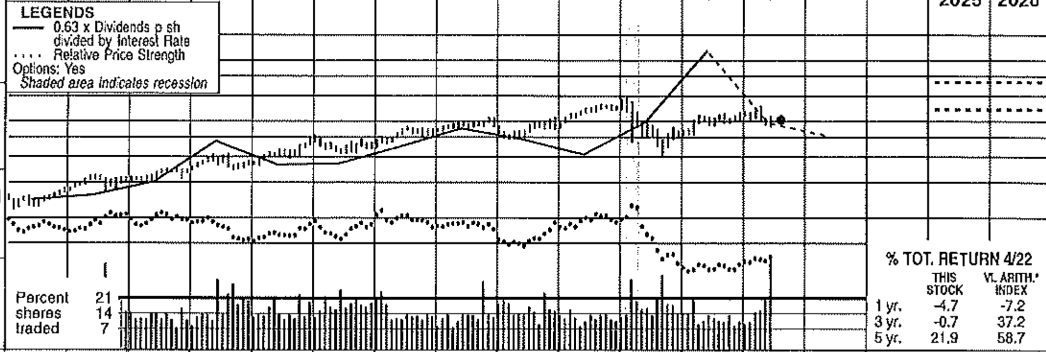
RECENT PRICE 48.98 | P/E RATIO 18.8 (Trailing: 21.1 Median: 18.0) | RELATIVE P/E RATIO 1.22 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 5 Lowered 6/10/22
SAFETY 2 Raised 10/22/21
TECHNICAL 3 Lowered 6/17/22
BETA .85 (1.00 = Market)

High:	26.0	28.1	33.3	40.3	41.0	45.2	50.1	50.4	58.4	63.1	53.1	57.0
Low:	21.3	24.3	27.4	29.0	33.0	35.3	42.4	39.0	44.0	32.0	40.8	45.0

Target Price Range 2025 | 2026 | 2027

LEGENDS
— 0.63 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)
$42-$67 $55 (10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+55%)	14%
Low	55	(+10%)	7%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	142	149	178
to Sell	145	141	142
Hld's(000)	82480	81443	82974

Percent shares traded 21 14 7

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.7	-7.2
3 yr.	-0.7	37.2
5 yr.	21.9	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
24.32	27.87	27.89	23.99	23.67	24.06	23.89	23.18	24.29	21.38	21.62	22.54	22.30	23.75	23.96	26.80	27.35	28.20	Revenues per sh	30.75
4.64	5.21	4.71	4.07	4.82	4.98	5.15	4.93	6.08	5.37	5.76	6.16	6.65	6.97	7.63	7.25	7.40	8.00	"Cash Flow" per sh	9.25
1.14	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	2.60	2.90	Earnings per sh A	3.40
.68	.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	1.89	Div'd Decl'd per sh B ■ †	2.25
5.94	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	7.65	7.55	Cap'l Spending per sh	7.60
19.58	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	31.05	32.10	Book Value per sh C	35.50
62.50	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	89.50	89.50	Common Shs Outst'g D	89.50
23.4	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	Bold figures are		Avg Ann'l P/E Ratio	19.0
1.26	.63	.98	.96	.76	.78	.89	.95	.81	.89	1.00	1.01	.99	1.19	.85	.95	Value Line		Relative P/E Ratio	1.05
2.5%	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%	estimates		Avg Ann'l Div'd Yield	3.5%

CAPITAL STRUCTURE as of 3/31/22
Total Debt $3607 mill. Due in 5 Yrs $186 mill.
LT Debt $3585 mill. LT Interest $128 mill.
Incl. $273 mill. finance leases.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $4 mill.
Pension Assets-12/21 $800 mill. Oblig $972 mill.
Pfd Stock None

Common Stock 89,224,488 shs.
as of 4/21/22

MARKET CAP: $4.4 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
1805.0	1810.0	1900.0	1898.0	1923.0	2009.0	1991.0	2123.0	2145.0	2396.0	2450	2525	Revenues ($mill)	2750
141.0	137.0	175.0	172.0	193.0	204.0	212.0	214.0	247.0	244.0	235	260	Net Profit ($mill)	305
31.4%	23.2%	26.0%	20.7%	20.6%	25.3%	7.4%	11.2%	12.4%	8.6%	17.5%	17.5%	Income Tax Rate	17.5%
7.1%	14.6%	33.7%	19.8%	16.6%	8.8%	8.0%	7.0%	9.7%	10.2%	11.0%	10.0%	AFUDC % to Net Profit	8.0%
47.1%	51.3%	52.7%	47.8%	48.4%	50.1%	46.5%	51.3%	53.6%	56.8%	56.0%	56.0%	Long-Term Debt Ratio	58.0%
52.9%	48.7%	47.3%	52.2%	51.6%	49.9%	53.5%	48.7%	46.4%	43.2%	44.0%	44.0%	Common Equity Ratio	42.0%
3264.0	3735.0	4037.0	4329.0	4544.0	4842.0	4684.0	5323.0	5628.0	6265.0	6295	6540	Total Capital ($mill)	7550
4392.0	4880.0	5679.0	6012.0	6434.0	6741.0	6887.0	7161.0	7539.0	8005.0	8260	8480	Net Plant ($mill)	9000
5.9%	5.1%	5.8%	5.4%	5.6%	5.5%	5.8%	5.1%	5.6%	4.9%	5.0%	5.0%	Return on Total Cap'l	5.0%
8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	8.5%	8.3%	9.5%	9.0%	8.5%	9.0%	Return on Shr. Equity	9.5%
8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	8.5%	8.3%	9.5%	9.0%	8.5%	9.0%	Return on Com Equity E	9.5%
3.5%	2.9%	4.6%	3.3%	3.5%	3.6%	3.5%	3.1%	4.1%	3.5%	2.5%	3.0%	Retained to Com Eq	3.5%
57%	61%	50%	56%	57%	58%	59%	63%	57%	61%	69%	65%	All Div'ds to Net Prof	66%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+1.2	+.4	+5.1
Avg. Indust. Use (MWH)	17827	18472	20002
Avg. Indust. Revs. per KWH (¢)	4.75	4.99	5.22
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3765	3771	4447
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+1.5	+.6
Fixed Charge Cov. (%)	265	187	261

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	0.5%	2.0%	3.5%
"Cash Flow"	5.0%	5.0%	4.0%
Earnings	5.0%	4.5%	4.5%
Dividends	4.5%	6.0%	6.0%
Book Value	3.5%	3.0%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	573.0	460.0	542.0	548.0	2123.0
2020	573.0	469.0	547.0	556.0	2145.0
2021	609.0	537.0	642.0	608.0	2396.0
2022	626.0	544	655	625	2450
2023	645	560	675	645	2525

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.82	.28	.61	.68	2.39
2020	.91	.43	.84	.57	2.75
2021	1.07	.36	.56	.73	2.72
2022	.67	.45	.66	.82	2.60
2023	.91	.47	.68	.84	2.90

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.34	.34	.3625	.3625	1.41
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		

BUSINESS: Portland General Electric Company (PGE) provides electricity to 917,000 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, 47%; commercial, 29%; industrial, 11%; other, 13%. Generating sources: gas, 37%; wind, 9%; coal, 8%; hydro, 4%; purchased, 42%. Fuel costs: 34% of revenues. '21 reported depreciation rate: 3.4%. Has 2,800 full-time employees. Chairman: Jack E. Davis. President and Chief Executive Officer: 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 (PGE) received the order on its general rate case, and it was as expected on the main issues up for review. The allowed return on equity remains unchanged at 9.5%. The decoupling mechanism was eliminated and a major storm balancing account established. The Faraday repowering project, still under construction, was not included in this case, and will have to be covered separately. Overall, the order authorized an average price increase of about 3.2% from May 9th.

However, management is reducing this year's earnings guidance mainly due to a minor regulatory stipulation. PGE recorded a reduction to wildfire restoration deferalls in the first quarter. Higher maintenance costs are also to blame. We cut our 2022 and 2023 EPS estimates by $0.30 and $0.15, respectively.

Longer Term, PGE leadership's bottom-line growth target of 4%-6% still seems feasible. Next year will benefit from a full year of rate relief against an easy comparison. From 2023 out to mid-decade we're projecting a 5.5% growth rate in earnings. Accelerating load growth, thanks to the healthy economy of the utility's service territory, where there is a vibrant tech sector, is the main factor.

The utility is awaiting decisions on its RFP (request for proposals). PGE wants to add renewables and "nonemitting" capacity. The short list should be known by the end of this month and the goal is for contracts to be executed with the winning bidders by yearend. If PGE winds up building some of this capacity itself, it will likely have to fund some of the construction with issued equity.

In keeping with its targeted dividend growth objectives, the board of directors raised the payout 5.2%. PGE targets a long-term growth rate of 5%-7% and a payout ratio of 60%-70%. Our projections assume a 6% CAGR to mid-decade.

Untimely PGE has a dividend yield 30 basis points above its industry average. And EPS and dividend growth rates are at least 70 basis points above the averages. Reduced guidance and market weakness have the stock down 12% since our April report. Utility investors may want to consider it for a long-term holding.

Anthony J. Glennon *July 22, 2022*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '13, (42¢); '17, (19¢); '20, ($1.03). Next earnings report due July 28. (B) Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan available. † Shareholder investment plan available. (C) Incl. deferred charges. In '21: $533 mill., $5.96/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on common equity in '22: 9.5%; earned on avg. com. eq., '21: 9.2%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	55
Earnings Predictability	75

PPL CORPORATION NYSE-PPL

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
28.11	21.6	(Trailing: NMF Median: 13.0)	1.30	2.9%	VALUE LINE

TIMELINESS 5 Lowered 11/26/21

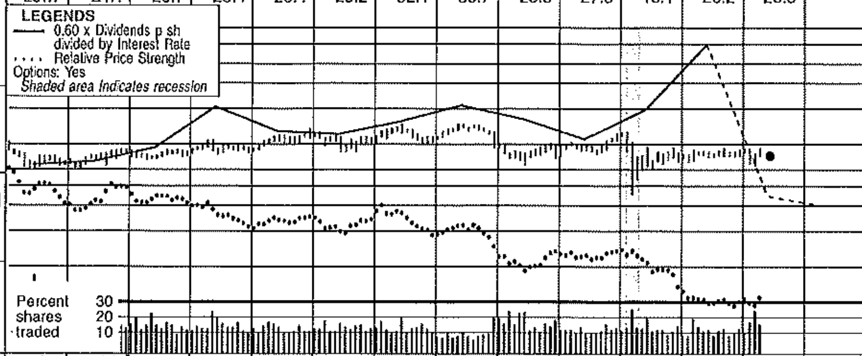
SAFETY 3 Lowered 3/18/22

TECHNICAL 4 Raised 5/13/22

BETA 1.10 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	30.3	30.2	33.6	38.1	36.7	39.9	40.2	32.5	36.3	36.8	30.7	30.5
Low:	24.1	26.7	28.4	29.4	29.2	32.1	30.7	25.3	27.8	18.1	26.2	25.3

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$24-$33	$29 (0%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+5%)	5%
Low	20	(-30%)	-4%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	410	389	377
to Sell	326	331	387
Hld's(000)	497392	491851	484161

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.1	-7.2
3 yr.	5.0	37.2
5 yr.	-4.8	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
17.92	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	*8.15*	*8.40*	Revenues per sh	*9.25*
4.26	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	*2.90*	*3.05*	"Cash Flow" per sh	*3.50*
2.29	2.63	2.45	1.19	2.29	2.61	2.61	2.38	2.38	2.37	2.79	2.11	2.58	2.37	2.04	.53	*1.30*	*1.35*	Earnings per sh A	*1.60*
1.10	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	*.80*	*.84*	Div'd Decl'd per sh B ■	*1.00*
3.62	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	*2.15*	*1.90*	Cap'l Spending per sh	*1.75*
13.30	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	*19.20*	*19.80*	Book Value per sh C	*21.75*
385.04	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	*737.00*	*739.00*	Common Shs Outst'g D	*745.00*
14.1	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	NMF	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.76	.92	1.06	1.71	.76	.66	.69	.72	.74	.70	.67	.89	.61	.71	.71	NMF	*Value Line*		Relative P/E Ratio	*.95*
3.4%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 12/31/21
Total Debt $11209 mill. **Due in 5 Yrs** $3000 mill.
LT Debt $10666 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: 2.0x)

Leases, Uncapitalized Annual rentals $23 mill.
Pension Assets-12/21 $3887 mill.
Oblig $3989 mill.

Pfd Stock None

Common Stock 735,361,885 shs.
as of 1/31/22

MARKET CAP: $21 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
12286	11860	11499	7669.0	7517.0	7447.0	7785.0	7769.0	7607.0	5783.0	*6000*	*6200*	Revenues ($mill)	*6900*
1536.0	1541.0	1583.0	1603.0	1902.0	1449.0	1827.0	1746.0	1571.0	401.0	*965*	*1015*	Net Profit ($mill)	*1195*
26.2%	23.1%	33.0%	22.5%	25.4%	24.2%	20.0%	19.0%	20.3%	23.0%	*23.0%*	*23.0%*	Income Tax Rate	*23.0%*
4.1%	3.7%	2.8%	1.6%	1.6%	1.9%	2.0%	1.9%	1.8%	6.0%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
64.1%	62.3%	58.0%	65.2%	64.3%	64.8%	63.3%	61.5%	61.7%	43.7%	*45.5%*	*47.5%*	Long-Term Debt Ratio	*49.5%*
35.9%	37.7%	42.0%	34.8%	35.7%	35.2%	36.7%	38.5%	38.3%	56.3%	*54.5%*	*52.5%*	Common Equity Ratio	*50.5%*
29205	33058	32484	28482	27707	30608	31726	33712	34926	24389	*25975*	*27775*	Total Capital ($mill)	*31900*
30032	33087	34597	30382	30074	33092	34458	36482	38892	25470	*25900*	*26050*	Net Plant ($mill)	*25900*
7.0%	6.2%	6.5%	7.1%	8.4%	6.2%	7.2%	6.6%	5.9%	2.6%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.0%*
14.7%	12.4%	11.6%	16.2%	19.2%	13.5%	15.7%	13.4%	11.7%	2.9%	*7.0%*	*7.0%*	Return on Shr. Equity	*7.5%*
14.6%	12.4%	11.6%	16.2%	19.2%	13.5%	15.7%	13.4%	11.7%	2.9%	*7.0%*	*7.0%*	Return on Com Equity E	*7.5%*
6.7%	5.3%	4.5%	6.0%	8.8%	3.5%	6.0%	4.3%	2.2%	NMF	*2.5%*	*2.5%*	Retained to Com Eq	*3.0%*
54%	57%	61%	63%	54%	74%	62%	68%	81%	NMF	*61%*	*61%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-3.4	-5.2	+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, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	283	278	154

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-7.5%	-7.0%	*NMF*
"Cash Flow"	-1.5%	-5.0%	*NMF*
Earnings	-2.0%	-8.0%	*NMF*
Dividends	1.5%	2.0%	*NMF*
Book Value	.5%	1.5%	*NMF*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2079	1803	1933	1954	7769.0
2020	2054	1739	1885	1929	7607.0
2021	1498	1288	1512	1485	5783.0
2022	*1550*	*1400*	*1525*	*1525*	*6000*
2023	*1600*	*1450*	*1575*	*1575*	*6200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.64	.60	.65	.48	2.37
2020	.72	.45	.50	.38	2.04
2021	.26	d.20	.27	.19	.53
2022	*.35*	*.30*	*.35*	*.30*	*1.30*
2023	*.36*	*.31*	*.37*	*.31*	*1.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.395	.41	.41	.41	1.63
2019	.41	.4125	.4125	.4125	1.65
2020	.4125	.415	.415	.415	1.66
2021	.415	.415	.415	.415	1.66
2022	.415	.20			

BUSINESS: PPL Corporation (formerly PP&L Resources, Inc.) is a holding company for PPL Electric Utilities (formerly Pennsylvania Power & Light Company), which distributes electricity to 1.4 million customers in eastern & central PA. Acq'd Kentucky Utilities and Louisville Gas and Electric (1.3 mill. customers) 11/10. Sold gas distribution sub. in '08. Spun off power-generating sub. in '15. Sold electric distribution sub. in U.K. in '21. Electric revenue breakdown: residential, 46%; commercial, 22%; industrial, 11%; other, 21%. Fuel costs: 25% of revenues. '21 reported deprec. rate: 3.6%. Has 5,600 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.

The proposed acquisition of Narragansett Electric by PPL Corporation has hit a snag. PPL has agreed to pay $3.8 billion in cash for the utility, which has about 780,000 electric and gas customers in Rhode Island. The companies have received all needed regulatory approvals to complete the deal. However, the Rhode Island Superior Court issued a stay of the state commission's order after the attorney general appealed the decision. As this report went to press, the parties were involved in settlement discussions. Our estimates and projections do not include Narragansett Electric, which earned $135 million in the fiscal year that ended on March 31, 2021 (the latest data available).

As we had expected, the board of directors slashed the dividend. Last year, the sale of PPL's utilities in the United Kingdom raised $10.4 billion in cash (some of which is earmarked for the Narragansett Electric purchase), and lowered PPL's regulatory, political, and currency risks. However, this also reduced the company's earning power considerably. The dividend of $0.20 a share quarterly is based on PPL's current operations, and will likely be raised (perhaps by a nickel) if the Narragansett Electric acquisition goes through. Based on our 2022 earnings estimate, the current dividend would result in a payout ratio in the low 60% range. This is in line with other electric companies.

For the time being, earnings are more unpredictable than the stock's Earnings Predictability Index suggests. When — or even if — the Narragansett takeover will be completed is unknown. The market is more concerned about this than it is about where PPL's earnings will wind up in 2022, since the company's results won't include a full year of Narragansett's income even if the acquisition is completed.

We advise investors to stay on the sidelines for now. What PPL will do with the funds intended for Narragansett if the transaction falls through is unknown. The stock is untimely, the dividend yield is somewhat below average for a utility, and the equity (based on PPL's current configuration) doesn't stand out for its 18-month or 2025-2027 prospects.

Paul E. Debbas, CFA *May 13, 2022*

(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., Apr., 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	75
Price Growth Persistence	15
Earnings Predictability	50

P.S. ENTERPRISE GP. NYSE-PEG

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD
68.85	31.3	(Trailing: NMF / Median: 15.0)	1.89	3.2%

VALUE LINE

TIMELINESS 3 Raised 3/11/22
SAFETY 1 Raised 11/23/12
TECHNICAL 3 Lowered 4/1/22
BETA .90 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	35.5	34.1	37.0	43.8	44.4	47.4	53.3	56.7	63.9	62.2	67.1	75.6
Low:	28.0	28.9	29.7	31.3	36.8	37.8	41.7	46.2	50.0	34.8	53.8	61.0

Target Price Range 2025 | 2026 | 2027

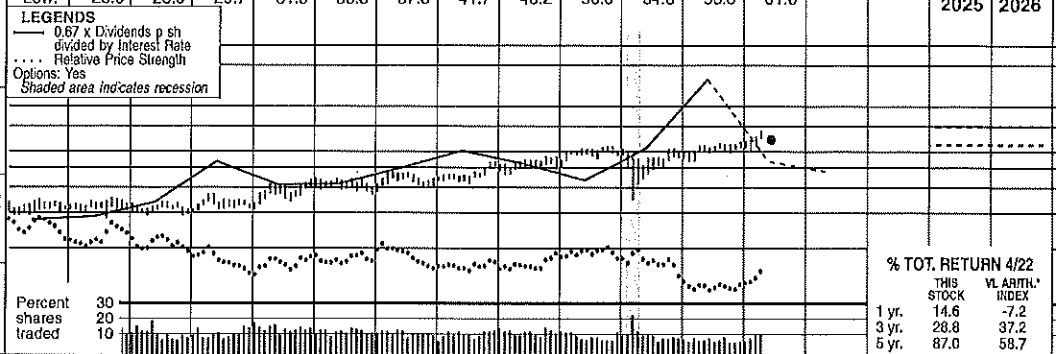
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$62-$87 $75 (10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+15%)	7%
Low	65	(-5%)	2%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	399	397	464
to Sell	331	333	353
Hld's(000)	358196	363353	364212



% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	14.6	-7.2
3 yr.	28.8	37.2
5 yr.	87.0	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
24.07	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	17.35	18.95	Revenues per sh	22.00
3.91	4.36	4.68	4.98	5.27	5.36	4.87	5.17	5.82	6.15	5.07	5.30	5.44	6.76	6.54	5.34	5.15	6.65	"Cash Flow" per sh	7.75
1.85	2.59	2.90	3.08	3.07	3.11	2.44	2.45	2.99	3.30	2.83	2.82	2.76	3.90	3.61	2.55	2.20	3.60	Earnings per sh A	4.25
1.14	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	Div'd Decl'd per sh B ■†	2.65
2.01	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	6.25	7.55	Cap'l Spending per sh	7.25
13.35	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	28.15	29.45	Book Value per sh C	35.25
505.29	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	496.00	496.00	Common Shs Outst'g D	496.00
17.8	16.5	13.6	10.0	10.4	10.4	12.8	13.5	12.6	12.4	15.3	16.3	18.7	15.1	14.9	24.1	Bold figures are		Avg Ann'l P/E Ratio	17.0
.96	.88	.82	.67	.66	.65	.81	.76	.66	.62	.80	.82	1.01	.80	.77	1.32	Value Line		Relative P/E Ratio	.95
3.5%	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%	estimates		Avg Ann'l Div'd Yield	3.7%

CAPITAL STRUCTURE as of 12/31/21
Total Debt $19438 mill. Due in 5 Yrs $9069 mill.
LT Debt $15219 mill. LT Interest $475 mill.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $40 mill.

Pension Assets-12/21 $6906 mill. Oblig $7240 mill.

Pfd Stock None

Common Stock 502,077,935 shs. as of 2/18/22

MARKET CAP: $35 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
9781.0	9968.0	10886	10415	9198.0	9161.0	9696.0	10076	9603.0	9722.0	8600	9400	Revenues ($mill)	10900
1239.0	1243.0	1518.0	1679.0	1436.0	1431.0	1399.0	1979.0	1829.0	1288.0	1105	1790	Net Profit ($mill)	2090
36.2%	39.5%	38.2%	37.4%	31.7%	37.3%	22.3%	15.9%	16.1%	19.6%	20.0%	20.0%	Income Tax Rate	20.0%
4.8%	4.6%	4.5%	5.5%	8.4%	10.6%	9.8%	5.5%	7.2%	13.4%	12.0%	7.0%	AFUDC % to Net Profit	6.0%
38.3%	40.4%	40.4%	40.3%	45.3%	46.6%	47.8%	47.7%	47.6%	51.3%	54.0%	55.0%	Long-Term Debt Ratio	56.5%
61.7%	59.6%	59.6%	59.7%	54.7%	53.4%	52.2%	52.3%	52.4%	48.7%	46.0%	45.0%	Common Equity Ratio	43.5%
17467	19470	20446	21900	24025	25915	27545	28832	30480	29657	30475	32550	Total Capital ($mill)	40100
19736	21645	23589	26539	29286	31797	34363	35844	37585	34366	36050	38350	Net Plant ($mill)	44300
8.1%	7.5%	8.4%	8.6%	6.8%	6.4%	6.0%	7.8%	6.9%	5.2%	4.5%	6.5%	Return on Total Cap'l	6.5%
11.5%	10.7%	12.5%	12.9%	10.9%	10.3%	9.7%	13.1%	11.4%	8.9%	8.0%	12.0%	Return on Shr. Equity	12.5%
11.5%	10.7%	12.5%	12.9%	10.9%	10.3%	9.7%	13.1%	11.4%	8.9%	8.0%	12.0%	Return on Com Equity E	12.5%
4.8%	4.4%	6.3%	6.8%	4.6%	4.1%	3.4%	6.8%	5.2%	1.6%	Nil	4.5%	Retained to Com Eq	4.5%
58%	59%	49%	47%	58%	61%	65%	48%	54%	80%	98%	63%	All Div'ds to Net Prof	63%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.9	-2.5	+1.3
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)	9753	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	361	298	273

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.0%	-.5%	2.0%
"Cash Flow"	2.0%	2.0%	4.0%
Earnings	1.0%	2.0%	4.0%
Dividends	3.5%	4.5%	5.0%
Book Value	5.0%	3.5%	2.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2980	2316	2302	2478	10076
2020	2781	2050	2370	2402	9603.0
2021	2889	1874	1903	3056	9722.0
2022	2313	1800	2237	2250	8600
2023	2800	1900	2350	2350	9400

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.38	.86	.80	.86	3.90
2020	.88	.89	.99	.85	3.61
2021	1.28	.39	--	.88	2.55
2022	d.01	.75	.90	.56	2.20
2023	1.25	.80	.95	.60	3.60

Cal-endar	QUARTERLY DIVIDENDS PAID B ■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.45	.45	.45	.45	1.80
2019	.47	.47	.47	.47	1.88
2020	.49	.49	.49	.49	1.96
2021	.51	.51	.51	.51	2.04
2022	.54				

BUSINESS: Public Service Enterprise Group Incorporated 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 New Jersey, and PSEG Power LLC, a nonregulated power generator with nuclear, gas, and coal-fired plants in the Northeast. PSEG Energy Holdings is involved in renewable energy. The company no longer breaks out data on electric and gas operating statistics. Fuel costs: 36% of revenues. '21 reported depreciation rates (utility): 1.8%-2.6%. Has 12,700 employees. Chairman, President & CEO: Dr. Ralph Izzo. COO: 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 has completed the sale of its fossil-fueled generating assets. The deal raised $1.75 billion, and a previous sale of nonutility solar assets brought in $400 million. PSEG is repurchasing $500 million of common stock, and used the remainder of the funds for debt reduction. Following the divestiture of these nonregulated assets, some 90% of PSEG's income is generated by its regulated utility, Public Service Electric and Gas, with the remainder from its nonregulated nuclear facilities. This has lessened the company's business risk. However, PSEG took a sizable loss on the transactions, and booked a nonrecurring charge of $3.84 a share after writing down these assets last year.

Our 2022 earnings estimate requires an explanation. Our presentation *includes* mark-to-market accounting items because these are part of PSEG's ongoing results. This amounted to a pretax charge of $845 million in the first quarter, and sent the bottom line into the red. Operationally, PSE&G's income is advancing thanks to regulatory mechanisms that allow contemporaneous recovery of much of the utility's capital spending for transmission and distribution. The company's 2022 earnings guidance, which excludes mark-to-market items, is $3.35-$3.55 a share. Note that PSEG will lose the (undisclosed) income from the assets that were sold.

We look for solid profit growth in 2023. The key driver should be continued growth in income from PSE&G. The utility's capital budget is expected to be higher next year. There will also be a modest benefit from a decline in average shares outstanding.

As expected, the board of directors raised the quarterly dividend $0.03 a share (5.9%) in the first quarter. PSEG had signaled that such an increase was in the offing. We project similar growth in the disbursement through the period to 2025-2027.

This high-quality stock has a dividend yield that is about average, by utility standards. However, the equity lacks appeal for the 18-month span and the next 3 to 5 years. Like most utility issues, the recent quotation is within our 2025-2027 Target Price Range.

Paul E. Debbas, CFA *May 13, 2022*

(A) Diluted EPS. Excl. nonrec. gains (losses): '06, (35¢); '08, (96¢); '09, 6¢; '11, (34¢); '12, 7¢; '16, (30¢); '17, 28¢ (net); '18, 8¢; '19, (62¢); '20, 15¢; '21, ($3.84); gains from disc. ops.: '06, 12¢; '07, 3¢; '08, 40¢; '11, 13¢. Next earnings report due early Aug. (B) Div'ds historically paid in late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '21: $7.19/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '18: 9.6%; earned on avg. com. eq., '21: 8.0%. Regulatory Climate: Average.

Company's Financial Strength	A++
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	80

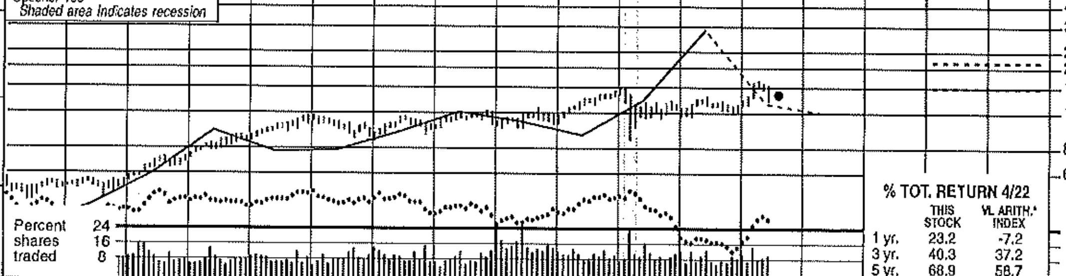
SEMPRA ENERGY NYSE-SRE

RECENT PRICE 148.53 | P/E RATIO 17.8 (Trailing: 19.9 Median: 20.0) | RELATIVE P/E RATIO 1.16 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 2 Raised 6/3/22
SAFETY 2 Raised 7/29/16
TECHNICAL 2 Lowered 7/22/22
BETA .95 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	56.0	72.9	93.0	116.3	116.2	114.7	123.0	127.2	154.5	161.9	144.9	173.3
Low:	44.8	54.7	70.6	86.7	89.4	86.7	99.7	100.5	106.1	88.0	114.7	129.7

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



Target Price Range 2025 | 2026 | 2027

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$128-$189 $159 (5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	215	(+45%)	12%
Low	160	(+10%)	5%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	404	453	476
to Sell	305	315	337
Hld's(000)	272986	269538	275892

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	23.2	-7.2
3 yr.	40.3	37.2
5 yr.	68.9	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
44.89	43.79	44.21	32.88	37.44	41.83	39.80	43.18	44.80	41.20	40.71	44.59	42.69	37.12	39.41	40.57	*44.45*	*48.20*	Revenues per sh	*55.75*
6.74	6.93	7.40	7.94	7.78	8.58	8.92	8.87	9.41	10.32	9.50	10.57	11.07	11.14	13.22	13.43	*14.75*	*16.15*	"Cash Flow" per sh	*19.50*
4.23	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	7.68	*8.35*	*8.90*	Earnings per sh A	*10.75*
1.20	1.24	1.37	1.56	1.56	1.92	2.40	2.52	2.84	2.80	3.02	3.29	3.58	3.87	4.18	4.40	*4.58*	*4.80*	Div'd Decl'd per sh B ■	*5.60*
7.28	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	*16.05*	*13.75*	Cap'l Spending per sh	*13.75*
28.66	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	*82.85*	*86.50*	Book Value per sh C	*100.75*
262.01	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	*315.00*	*305.00*	Common Shs Outst'g D	*305.00*
11.5	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	16.9	***Bold figures are***		Avg Ann'l P/E Ratio	*17.5*
.62	.74	.71	.67	.80	.74	.95	1.11	1.15	.99	1.28	1.22	1.10	1.20	.90	.92	***Value Line***		Relative P/E Ratio	*.95*
2.5%	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%	***estimates***		Avg Ann'l Div'd Yield	*3.0%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $26895 mill. Due in 5 Yrs $7358 mill.
LT Debt $24416 mill. LT Interest $791 mill.
Incl. $1335 mill. finance leases.
(LT interest earned: 2.6x)

Leases, Uncapitalized Annual rentals $73 mill.
Pension Assets-12/21 $3182 mill.
Oblig $3857 mill.
Pfd Stock $889 mill. Pfd Div'd $45 mill.
900,000 shs. 4.875%, cumulative.
Common Stock 314,304,370 shs.
as of 4/29/22
MARKET CAP: $46.7 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
9647.0	10557	11035	10231	10183	11207	11687	10829	11370	12857	*14000*	*14700*	Revenues ($mill)	*17000*
1079.0	1060.0	1162.0	1314.0	1065.0	1169.0	1607.0	1825.0	2316.0	2466.0	*2695*	*2810*	Net Profit ($mill)	*3310*
18.2%	26.5%	19.7%	19.2%	14.4%	24.5%	20.1%	17.9%	18.0%	30.0%	*19.0%*	*19.0%*	Income Tax Rate	*19.0%*
17.2%	11.2%	14.4%	15.3%	22.2%	21.9%	12.6%	10.0%	8.7%	8.8%	*9.0%*	*8.0%*	AFUDC % to Net Profit	*7.0%*
52.8%	50.5%	51.7%	52.6%	52.7%	56.4%	55.7%	51.0%	48.2%	44.8%	*46.0%*	*47.5%*	Long-Term Debt Ratio	*46.5%*
46.7%	49.4%	48.2%	47.3%	47.3%	43.5%	38.4%	43.4%	44.8%	53.3%	*52.0%*	*51.0%*	Common Equity Ratio	*52.0%*
22002	22281	23513	24963	27400	29135	38769	40734	45174	47069	*50025*	*51750*	Total Capital ($mill)	*59300*
25191	25460	25902	28039	32931	36503	36796	36452	40003	43894	*46950*	*49000*	Net Plant ($mill)	*54000*
6.1%	6.0%	6.1%	6.4%	5.0%	5.1%	5.1%	5.5%	6.1%	6.1%	*6.5%*	*6.5%*	Return on Total Cap'l	*6.5%*
10.4%	9.6%	10.2%	11.1%	8.2%	9.2%	9.4%	9.1%	9.9%	9.5%	*10.0%*	*10.5%*	Return on Shr. Equity	*10.5%*
10.4%	9.6%	10.3%	11.1%	8.2%	9.2%	10.0%	9.5%	10.6%	9.6%	*10.0%*	*10.5%*	Return on Com Equity E	*10.5%*
5.1%	4.1%	5.0%	5.8%	2.9%	3.3%	4.1%	3.9%	4.8%	4.3%	*4.5%*	*5.0%*	Retained to Com Eq	*5.0%*
52%	58%	52%	48%	65%	65%	62%	62%	58%	57%	*55%*	*55%*	All Div'ds to Net Prof	*53%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-4.3	-.4	-3.7
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	+.8	+.9
Fixed Charge Cov. (%)	181	159	NMF

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	0.5%	-1.5%	*6.0%*
"Cash Flow"	4.5%	5.5%	*7.5%*
Earnings	4.5%	8.5%	*7.5%*
Dividends	9.5%	8.0%	*5.0%*
Book Value	6.0%	7.5%	*6.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2898	2230	2758	2943	10829
2020	3029	2526	2644	3171	11370
2021	3259	2741	3013	3844	12857
2022	3820	*3025*	*3225*	*3930*	*14000*
2023	*4100*	*3150*	*3350*	*4100*	*14700*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.78	.85	2.00	1.34	5.97
2020	2.53	1.58	1.31	1.88	7.38
2021	2.87	1.37	1.49	1.95	7.68
2022	2.67	*1.87*	*1.93*	*1.88*	*8.35*
2023	*2.85*	*2.00*	*2.05*	*2.00*	*8.90*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.8225	.895	.895	.895	3.51
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		

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 most of its power; the rest is gas. Has nonutility subsidiaries, incl. IEnova in Mexico. Sold commodities business in '10. Power costs: 20% of revenues. '21 reported deprec. rates: 2.6%-7.2%. Has 15,400 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.

Timely SRE stock remains a top year-to-date performer, despite a healthy correction since our April report. The price had been up 30%, but has since fallen to a 12% gain, still comparing favorably to the average electric utility stock (-3%) and S&P 500 (-19%). Sempra's ability to prosper even in tough economic times is surely a key factor. The company's nonregulated liquefied natural gas (LNG) export operation has also caught investors' attention, as the demand for LNG has increased sharply with Russian gas closed to the West. It should be noted, while the long-term fundamentals of this business are appealing, it's a methodical operation based on multiyear capital-intensive projects and long-term fixed contracts.

Management is reiterating its guidance for mid-to-high single-digit earnings growth this year and next. Sempra will benefit from rate relief at its utility subsidiaries in California and solid growth at its utility in Texas. These factors should he the main drivers of annual profit gains. Our share-earnings estimates are within the company's targeted ranges of $8.10-$8.70 and $8.60-$9.20 in 2022 and 2023, respectively. We are assuming no change in the allowed return on equity (ROE), although a cost-of-capital case is pending in California. A provision under the state's regulatory mechanism would force a cut in the allowed ROE for SDG&E from 10.2% to 9.62%. The utility is making its case that tbe mechanism should not take effect due to extremely low interest rates garnered during the lockdowns. SDG&E is actually proposing an increase to its allowed ROE to 10.55%. Any change would only impact 2022 profits, retroactively to the start of the year.

Sempra continues to return value to shareholders. The company recently sold a 10% interest in its infrastructure unit for $1.73 billion. Leadership plans to use the cash for share repurchases and capital spending. Meanwhile, the annualized dividend was raised in the second quarter from $4.40 to $4.58. Longer term, we're projecting a 5% rate of growth.

SRE appears reasonably valued. The dividend yield is 40 basis points below the utility average. Yet, the company's dividend and EPS growth are well above it.

Anthony J. Glennon *July 22, 2022*

(A) Dil. EPS. Excl. nonrec. gain (loss): '09, (26¢); '10, ($1.05); '11, $1.15; '12, (98¢); '13, (30¢); '15, 14¢; '16, $1.23; '17, (17¢); '18, ($2.06); '19, 16¢; '20, (80¢); '21, ($3.67); '22, (74¢); disc. ops.: '19, 95¢; '20, $6.32. '20 & '21 EPS don't sum due to chg.in shs. Next egs. report Aug. (B) Div'ds paid mid-Jan., Apr., July, Oct. ■ Div'd reinv. avail. (C) Incl. Intang. In '21: $12.57/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq.: SDG&E in '20: 10.2%; SoCalGas in '20: 10.05%; earned on avg. com. eq., '21: 5.5%. Reg. Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	60
Earnings Predictability	70

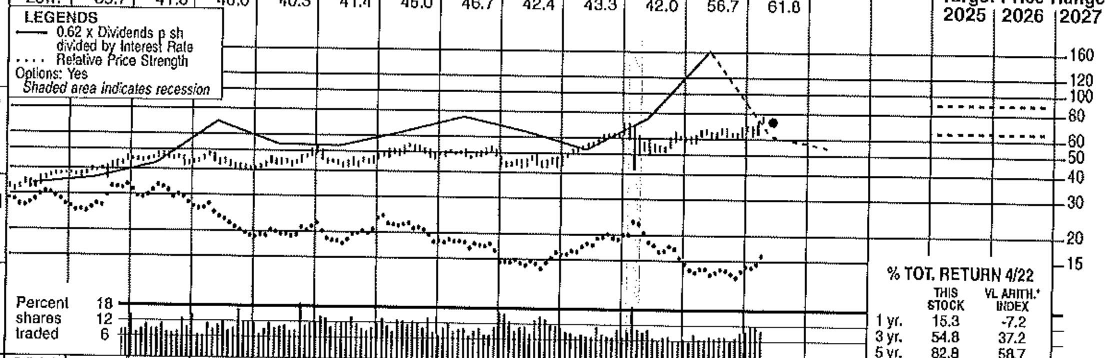
SOUTHERN COMPANY NYSE-SO

RECENT PRICE 73.21 | P/E RATIO 20.6 (Trailing: 22.2; Median: 17.0) | RELATIVE P/E RATIO 1.24 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 4 Lowered 8/13/21
SAFETY 2 Lowered 2/21/14
TECHNICAL 3 Raised 4/29/22
BETA .90 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	46.7	48.6	48.7	51.3	53.2	54.6	53.5	49.4	64.3	71.1	68.9	77.2
Low:	35.7	41.8	40.0	40.3	41.4	46.0	46.7	42.4	43.3	42.0	56.7	61.8

Target Price Range
2025 | 2026 | 2027



18-Month Target Price Range
Low-High: $64-$92 | Midpoint (% to Mid): $78 (5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+25%)	9%
Low	65	(-10%)	1%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	743	676	856
to Sell	580	598	553
Hld's(000)	629680	633336	643341

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	15.3	-7.2
3 yr.	54.8	37.2
5 yr.	82.8	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
19.24	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	23.75	24.85	Revenues per sh	28.75
4.01	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	7.30	7.65	"Cash Flow" per sh	9.25
2.10	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	3.55	3.70	Earnings per sh A	4.75
1.54	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	Div'd Decl'd per sh B ■	3.10
4.01	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	Cap'l Spending per sh	7.50
15.24	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	27.05	28.00	Book Value per sh C	32.25
746.27	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	1070.0	1070.0	Common Shs Outst'g D	1070.0
16.2	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	Bold figures are		Avg Ann'l P/E Ratio	16.5
.87	.85	.97	.90	.95	.99	1.08	.91	.84	.80	.93	.78	.82	.94	.92	1.00	Value Line		Relative P/E Ratio	.90
4.5%	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%	estimates		Avg Ann'l Div'd Yield	4.0%

CAPITAL STRUCTURE as of 3/31/22
Total Debt $54156 mill. Due in 5 Yrs $15427 mill.
LT Debt $50633 mill. LT Interest $1754 mill.
Incl. $215 mill. finance leases.
(LT interest earned: 3.3x)
Leases, Uncapitalized Annual rentals $307 mill.
Pension Assets-12/21 $17225 mill.
Oblig $16382 mill.
Pfd Stock $291 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 1,062,524,675 shs.
MARKET CAP: $78 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
16537	17087	18467	17489	19896	23031	23495	21419	20375	23113	25400	26600	Revenues ($mill)	30850
2415.0	2439.0	2567.0	2647.0	2757.0	3269.0	3096.0	3354.0	3481.0	3670.0	3695	3875	Net Profit ($mill)	4980
35.6%	34.8%	33.8%	33.4%	28.5%	25.2%	21.3%	15.9%	14.3%	16.3%	15.0%	15.0%	Income Tax Rate	15.0%
9.4%	11.6%	13.9%	13.2%	11.9%	7.6%	6.8%	6.0%	6.6%	7.7%	8.0%	8.0%	AFUDC % to Net Profit	6.0%
49.9%	51.5%	49.5%	52.8%	61.5%	64.5%	62.0%	60.1%	61.5%	64.0%	63.5%	64.0%	Long-Term Debt Ratio	63.0%
47.3%	45.8%	47.3%	44.0%	35.7%	35.0%	37.6%	39.5%	38.1%	35.6%	36.0%	36.0%	Common Equity Ratio	37.0%
38653	41483	42142	46788	69359	68953	65750	69594	73336	78285	80550	83500	Total Capital ($mill)	93500
48390	51208	54868	61114	78446	79872	80797	83080	87634	91108	95150	99350	Net Plant ($mill)	110000
7.3%	6.8%	7.1%	6.6%	4.9%	5.9%	5.9%	6.0%	5.9%	5.8%	5.5%	5.5%	Return on Total Cap'l	6.5%
12.5%	12.1%	12.1%	12.0%	10.3%	13.3%	12.4%	12.1%	12.3%	13.0%	12.5%	13.0%	Return on Shr. Equity	14.5%
12.8%	12.5%	12.5%	12.6%	11.0%	13.4%	12.5%	12.1%	12.4%	13.1%	13.0%	13.0%	Return on Com Equity E	14.5%
3.6%	3.2%	3.2%	3.1%	2.5%	3.9%	2.6%	2.8%	2.8%	3.1%	3.0%	3.5%	Retained to Com Eq	5.0%
73%	75%	75%	76%	78%	72%	79%	77%	78%	76%	78%	77%	All Div'ds to Net Prof	67%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% 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 '19-'21 to '25-'27
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%

Calendar	QUARTERLY REVENUES (mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	5412	5098	5995	4914	21419
2020	5018	4620	5620	5117	20375
2021	5910	5198	6238	5767	23113
2022	6648	5700	6852	6200	25400
2023	6950	6000	7150	6500	26600

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.75	.85	1.25	.32	3.17
2020	.81	.75	1.18	.51	3.25
2021	1.09	.67	1.22	.44	3.42
2022	.97	.80	1.30	.48	3.55
2023	1.00	.85	1.35	.50	3.70

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.58	.60	.60	.60	2.38
2019	.60	.62	.62	.62	2.46
2020	.62	.64	.64	.64	2.54
2021	.64	.66	.66	.66	2.62
2022	.66	.68			

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 expects to complete two nuclear units by the first quarter and fourth quarter of 2023, respectively. This is later than the company expected when it reported third-quarter earnings in early November, but unchanged from when it reported fourth-period results in mid-February. The project, which will add two units at the site of the Vogtle station, has had numerous delays and cost overruns. The most recent capital-cost estimate for the utility's 45.7% share of the project is $10.4 billion, with $1.7 billion remaining.

We look for earnings to advance moderately in 2022 and 2023. The utilities should benefit from rate relief and volume growth. Georgia Power will file a rate case next month, which ought to boost its earning power next year. Our 2022 estimate, which we trimmed by a nickel a share, is at the midpoint of management's guidance of $3.50-$3.60. Once the units are completed, however, earnings growth will probably accelerate. In fact, Southern Company has issued a preliminary profit target of $4.00-$4.30 a share for 2024, which we think is attainable. However . . .

Any further delays in the Vogtle project would hurt the bottom line. The company estimates that a three-month delay at Unit 3 would cost $0.02 a share, and the same delay at Unit 4 would cost $0.05. Our 2022 and 2023 estimates are based on the assumption that the project is completed in accordance with the current schedule.

The board of directors raised the dividend in the current quarter. The increase was $0.02 a share (3.0%), the same as in each of the past five years. We think dividend growth will accelerate along with earnings growth once Vogtle 3 and 4 are completed.

The untimely stock's dividend yield is just slightly above the utility average. The valuation has changed; for a while, the yield was more than a percentage point above the mean. It appears as if the market has become even more comfortable with the risks of the nuclear construction project. Total return potential is subpar for the next 18 months and low for the 3- to 5-year period.

Paul E. Debbas, CFA *May 13, 2022*

(A) Diluted EPS. Excl. nonrec. gain (losses): '09, (25¢); '13, (83¢); '14, (59¢); '15, (25¢); '16, (28¢); '17, ($2.37); '18, (78¢); '19, $1.30; '20, (17¢); '21, (54¢). Next earnings report due late July. (B) Div'ds paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. def'd charges. In '21: $19.83/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	90
Price Growth Persistence	35
Earnings Predictability	95

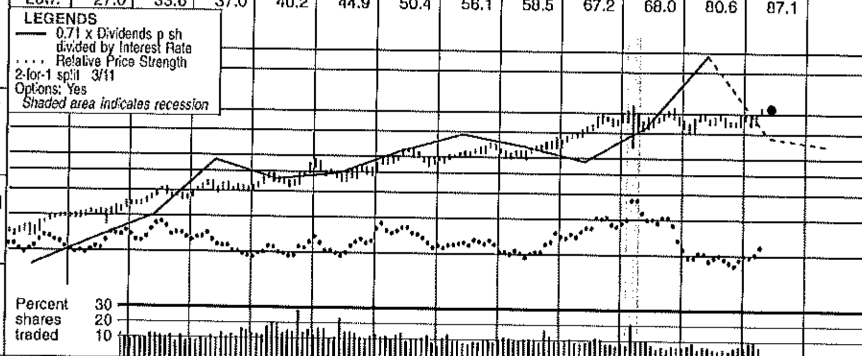
WEC ENERGY GROUP NYSE-WEC

RECENT PRICE 106.53 | P/E RATIO 24.2 (Trailing: 24.8; Median: 20.0) | RELATIVE P/E RATIO 1.45 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 3 Raised 1/7/22
SAFETY 1 Raised 3/23/12
TECHNICAL 3 Raised 4/29/22
BETA .90 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	35.4	41.5	45.0	55.4	58.0	66.1	70.1	75.5	98.2	109.5	99.9
Low:	27.0	33.6	37.0	40.2	44.9	50.4	56.1	58.5	67.2	68.0	80.6

High 108.4, Low 87.1 (2022)



Target Price Range 2025 | 2026 | 2027
200
160
100
80
60
50
40
30
20

18-Month Target Price Range
Low-High: $94-$134
Midpoint (% to Mid): $114 (5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	125	(+15%)	7%
Low	100	(-5%)	2%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	366	473	441
to Sell	387	362	380
Hld's(000)	236130	237652	233922

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.6	-7.2
3 yr.	37.5	37.2
5 yr.	90.3	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
17.08	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	*28.20*	*29.30*	Revenues per sh	*33.00*
2.90	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	*8.05*	*8.55*	"Cash Flow" per sh	*10.25*
1.32	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	*4.40*	*4.70*	Earnings per sh A	*5.50*
.46	.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*	*3.11*	Div'd Decl'd per sh B ■	*3.80*
4.17	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	*9.35*	*9.30*	Cap'l Spending per sh	*9.25*
12.35	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	*35.90*	*37.35*	Book Value per sh C	*42.00*
233.94	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*	Common Shs Outst'g D	*315.43*
16.0	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	*Bold figures are*		Avg Ann'l P/E Ratio	*20.5*
.86	.88	.89	.89	.89	.89	1.01	.93	.93	1.07	1.04	1.01	1.06	1.25	1.28	1.19	*Value Line*		Relative P/E Ratio	*1.15*
2.2%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
	4246.4	4519.0	4997.1	5926.1	7472.3	7648.5	7679.5	7523.1	7241.7	8316.0	*8900*	*9250*	Revenues ($mill)	*10400*
	547.5	578.6	589.5	640.3	940.2	998.2	1060.5	1134.2	1201.1	1301.5	*1390*	*1485*	Net Profit ($mill)	*1750*
	35.9%	36.9%	36.0%	40.4%	37.6%	37.2%	13.8%	9.9%	15.9%	13.4%	*19.0%*	*19.0%*	Income Tax Rate	*19.0%*
	9.4%	4.5%	1.3%	4.5%	3.8%	1.6%	2.1%	1.8%	2.4%	1.9%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
	51.7%	50.6%	48.5%	51.2%	50.5%	48.0%	50.4%	52.5%	52.8%	55.3%	*55.0%*	*55.0%*	Long-Term Debt Ratio	*55.5%*
	48.0%	49.1%	51.2%	48.6%	49.3%	51.9%	49.4%	47.4%	47.1%	44.6%	*44.5%*	*44.5%*	Common Equity Ratio	*44.5%*
	8619.3	8626.6	8636.5	17809	18118	18238	19813	21355	22228	24467	*25375*	*26375*	Total Capital ($mill)	*29800*
	10572	10907	11258	19190	19916	21347	22001	23620	25707	26982	*28800*	*30500*	Net Plant ($mill)	*35100*
	7.9%	8.1%	8.1%	4.5%	6.3%	6.6%	6.5%	6.5%	6.5%	6.3%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
	13.1%	13.6%	13.2%	7.4%	10.5%	10.5%	10.8%	11.2%	11.4%	11.9%	*12.0%*	*12.5%*	Return on Shr. Equity	*13.0%*
	13.2%	13.6%	13.3%	7.4%	10.5%	10.5%	10.8%	11.2%	11.5%	11.9%	*12.5%*	*12.5%*	Return on Com Equity E	*13.0%*
	6.5%	5.9%	5.3%	2.1%	3.5%	3.6%	3.7%	3.8%	3.8%	4.1%	*4.0%*	*4.5%*	Retained to Com Eq	*4.0%*
	51%	57%	60%	71%	67%	66%	66%	66%	67%	66%	*66%*	*66%*	All Div'ds to Net Prof	*69%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $15128 mill. **Due in 5 Yrs** $4611.7 mill.
LT Debt $13514 mill. **LT Interest** $452.7 mill.
Incl. $12.1 mill. finance leases.
(LT interest earned: 4.4x)
Leases, Uncapitalized Annual rentals $6.8 mill.
Pension Assets-12/21 $3328.9 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: $34 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.5	-2.6	+3.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Lg. C&I 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 '19-'21 to '25-'27
Revenues	3.0%	2.5%	*5.0%*
"Cash Flow"	7.5%	9.0%	*6.5%*
Earnings	7.5%	8.0%	*6.0%*
Dividends	11.5%	7.5%	*7.0%*
Book Value	7.5%	6.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2377	1590	1608	1947	7523.1
2020	2108	1548	1651	1933	7241.7
2021	2691	1676	1746	2201	8316.0
2022	2908	*1800*	*1892*	*2300*	*8900*
2023	*3000*	*1875*	*1925*	*2450*	*9250*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.33	.74	.74	.77	3.58
2020	1.43	.76	.84	.76	3.79
2021	1.61	.87	.92	.71	4.11
2022	1.79	*.84*	*.97*	*.80*	*4.40*
2023	*1.80*	*.95*	*1.05*	*.90*	*4.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.5525	.5525	.5525	.5525	2.21
2019	.59	.59	.59	.59	2.36
2020	.6325	.6325	.6325	.6325	2.53
2021	.6775	.6775	.6775	.6775	2.71
2022	.7275	.7275			

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. '21 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 utilities in Wisconsin have filed general rate cases. The utilities are seeking electric increases totaling $334.4 million, gas hikes totaling $141.1 million, and a steam increase of $3.3 million. The utilities want to maintain their allowed returns on equity of 10.0% (except for Wisconsin Gas' 10.2%) and raise their common-equity ratio from 52.5% to 53.0%. The company is seeking to recover capital investments. It also wants to ask for higher rates in 2024, under certain circumstances. New tariffs are expected to take effect at the start of 2023.

We raised our 2022 earnings estimate by $0.05 a share, to $4.40. First-quarter earnings exceeded our $1.70-a-share estimate thanks in part to favorable weather conditions. Upon reporting March-period results in early May, WEC Energy raised its earnings target by $0.05 a share, to $4.34-$4.38. We are comfortable being slightly above this range given the company's track record of exceeding its guidance. The profit growth that is likely is being driven by rate relief (including concurrent recovery of $280 million-$300 million of gas-main replacements for Peoples Gas in Chicago), modest volume growth, and increased income from WEC Energy's nonutility renewable-energy projects. A 190-megawatt wind farm began operating in December of 2021, and two more projects (with a total capacity of 550 mw) are expected to attain commercial operation in the second half of 2022. One of these has experienced some delays, however.

WEC Energy's goal for annual earnings growth is 6%-7%. The aforementioned factors should continue to lift the company's earning power. We boosted our 2023 earnings estimate by a nickel a share, to $4.70. This would provide an increase of 7% above our 2022 estimate.

The utility is building two liquefied natural gas facilities in Wisconsin. These are expected to come on line in 2023 and 2024 at a cost of $370 million. This will help maintain reliability.

The dividend yield is a cut below the utility average. This reflects the company's consistency and predictability. The Safety rank is 1 (Highest), too. But total returns don't stand out for the next 18 months or the 3- to 5-year period.

Paul E. Debbas, CFA *June 10, 2022*

(A) Diluted EPS. Excl. gain on discontinued ops.: '11, 6¢; nonrecurring gain: '17, 65¢. Next earnings report due early August. (B) Div'ds paid in early Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '21: $20.03/sh. (D) In mill., adj. for split. (E) Rate base: Nat 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	65
Earnings Predictability	100

XCEL ENERGY NDQ-XEL

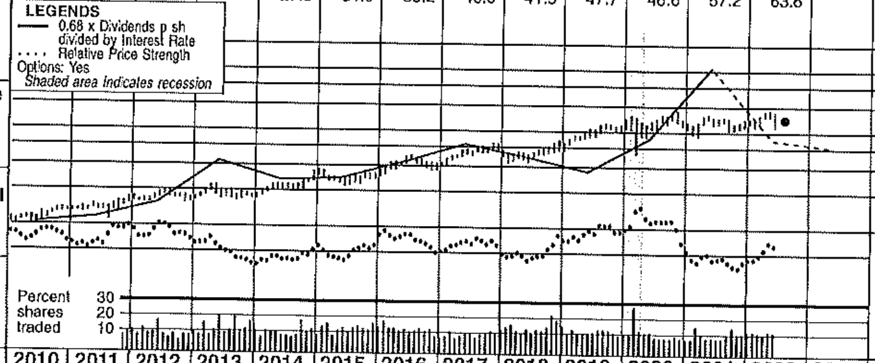
RECENT PRICE 69.89 | P/E RATIO 22.2 (Trailing: 23.4, Median: 19.0) | RELATIVE P/E RATIO 1.44 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 3 Raised 12/31/21
SAFETY 1 Raised 5/1/15
TECHNICAL 2 Lowered 7/15/22
BETA .80 (1.00 = Market)

High:	27.8	29.9	31.8	37.6	38.3	45.4	52.2	54.1	66.1	76.4	72.9	76.6
Low:	21.2	25.8	26.8	27.3	31.8	35.2	40.0	41.5	47.7	46.6	57.2	63.6

Target Price Range: 2025 | 2026 | 2027

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



18-Month Target Price Range
Low-High: $67-$95 | Midpoint (% to Mid): $81 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+30%)	9%
Low	75	(+5%)	5%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	355	449	458
to Sell	343	338	340
Hld's(000)	411220	413762	418018

Percent shares traded: 30, 20, 10

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.3	-7.2
3 yr.	41.5	37.2
5 yr.	88.9	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
24.16	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	26.50	27.25	Revenues per sh	29.50
3.61	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	7.75	8.30	"Cash Flow" per sh	10.00
1.35	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	3.15	3.35	Earnings per sh A	4.00
.88	.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	Div'd Decl'd per sh B ■ †	2.50
4.00	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	9.65	9.00	Cap'l Spending per sh	9.00
14.28	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	30.15	31.65	Book Value per sh C	37.00
407.30	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	547.00	550.00	Common Shs Outst'g D	561.00
14.8	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	Bold figures are		Avg Ann'l P/E Ratio	20.0
.80	.89	.82	.85	.90	.89	.94	.84	.81	.83	.97	1.02	1.02	1.19	1.23	1.23	Value Line		Relative P/E Ratio	1.10
4.4%	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%	estimates		Avg Ann'l Div'd Yield	3.1%

CAPITAL STRUCTURE as of 3/31/22
Total Debt $23381 mill. Due in 5 Yrs $4911 mill.
LT Debt $21534 mill. LT Interest $809 mill.
Incl. $73 mill. finance leases.
(LT interest earned: 2.9x)

Leases, Uncapitalized Annual rentals $69 mill.
Pension Assets-12/21 $3670 mill. Oblig $3718 mill.

Pfd Stock None

Common Stock 544,653,284 shs.
as of 4/21/22
MARKET CAP: $38.1 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
10128	10915	11686	11024	11107	11404	11537	11529	11526	13431	14500	15000	Revenues ($mill)	16500
905.2	948.2	1021.3	1063.6	1123.4	1171.0	1261.0	1372.0	1473.0	1597.0	1720	1855	Net Profit ($mill)	2260
33.2%	33.8%	33.9%	35.8%	34.1%	30.7%	12.6%	8.5%	8.5%	--	NMF	NMF	Income Tax Rate	NMF
10.8%	13.4%	12.5%	7.7%	7.8%	9.4%	12.4%	8.3%	10.7%	6.2%	7.0%	6.0%	AFUDC % to Net Profit	5.0%
53.3%	53.3%	53.0%	54.1%	56.3%	55.9%	56.4%	56.8%	57.4%	58.2%	58.0%	58.0%	Long-Term Debt Ratio	58.0%
46.7%	46.7%	47.0%	45.9%	43.7%	44.1%	43.6%	43.2%	42.6%	41.8%	42.0%	42.0%	Common Equity Ratio	42.0%
19018	20477	21714	23092	25216	25975	28025	30646	34220	37391	39150	41600	Total Capital ($mill)	49200
23809	26122	28757	31206	32842	34329	36944	39483	42950	45457	48225	50475	Net Plant ($mill)	57000
6.1%	6.0%	6.0%	5.8%	5.7%	5.8%	5.7%	5.6%	5.4%	5.3%	5.5%	5.5%	Return on Total Cap'l	5.5%
10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	10.1%	10.2%	10.5%	10.5%	Return on Shr. Equity	11.0%
10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	10.1%	10.2%	10.5%	10.5%	Return on Com Equity E	11.0%
4.7%	4.5%	4.5%	4.3%	4.0%	3.9%	4.3%	4.4%	4.2%	4.2%	4.0%	4.0%	Retained to Com Eq	4.0%
54%	54%	55%	57%	61%	62%	58%	58%	58%	59%	62%	62%	All Div'ds to Net Prof	62%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-1.2	-2.3	+1.4
Large C & I Use (MWH)	NA	NA	NA
Large C & I Revs. per KWH (¢)	5.96	5.78	6.60
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	20146	19665	19849
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	NA	NA
Fixed Charge Cov. (%)	272	252	262

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	.5%	4.5%
"Cash Flow"	6.5%	7.5%	7.0%
Earnings	6.0%	6.0%	6.0%
Dividends	5.5%	6.0%	6.5%
Book Value	5.0%	5.0%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	3141	2577	3013	2798	11529
2020	2811	2586	3182	2947	11526
2021	3541	3068	3467	3355	13431
2022	3751	3270	3835	3644	14500
2023	3950	3400	3950	3700	15000

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.61	.46	1.01	.56	2.64
2020	.56	.54	1.14	.54	2.79
2021	.67	.58	1.13	.58	2.96
2022	.70	.62	1.20	.63	3.15
2023	.75	.65	1.30	.65	3.35

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.36	.38	.38	.38	1.50
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		

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: 3.7 mill. electric, 2.1 mill. gas. Electric revenue breakdown: residential, 31%; small comm'l & ind'l, 36%; large comm'l & ind'l, 18%; other, 15%. Generating sources not available. Fuel costs: 43% of revenues. '21 reported deprec. rate: 3.5%. Has 11,300 employees. Chrmn: Ben Fowke. Pres. & CEO: Bob Frenzel. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

At Xcel Energy, rate relief is spurring steady earnings gains. Numerous increases are as a result of placing renewable-energy projects in the rate base, for which regulated utilities are allowed to earn a state-specified return on equity (ROE). Management is also effectively controlling costs despite inflation. Our 2022 earnings estimate remains at the midpoint of Xcel's guidance of $3.10-$3.20 a share, given first-quarter results were in line with our forecast. (We assume no disallowance of the extraordinary gas costs that NSP incurred last year; the Minnesota commission is considering whether there was any imprudence.) Meanwhile, our projections for solid profit gains in 2023 and beyond are based on the same factors (see below). Company leadership has a stated earnings growth objective of 5%-7% and a solid track record that underscores its goal (see Annual Rates box).

In that vein, Xcel has numerous pending rate cases. In Minnesota, NSP filed for electric rate hikes of $396 million in 2022, $150 million in 2023, and $131 million in 2024, based on a ROE of 10.2% and a common-equity ratio of 52.5%. NSP also filed for a gas increase of $36 million, based on a 10.5% ROE and the same equity ratio. Interim hikes of $247 million (electric) and $25 million (gas) took effect at the start of 2022. In Colorado, PSCo filed for a gas increase of $107 million (excluding revenues now being recovered through surcharges), followed by $40 million in 2023 and $41 million in 2024, based on a ROE of 10.25% and a common-equity ratio of 55.7%. New tariffs are expected to take effect in November. In Texas, SPS is awaiting a ruling on a settlement that would raise rates by $89 million, retroactive to mid-March of 2021.

The company continues to deliver shareholder value. A solid and consistent ROE has been achieved over the course of both good and difficult economic times. In April, the annualized dividend was raised from $1.83 to $1.95, in line with our 6.5% projected growth rate. The shares look fully valued with a dividend yield 60 basis points below the utility average. Yet, the growth rate is 210 basis points above it. We like XEL's valuation when it has a forward yield above 3.1%.

Anthony J. Glennon — *July 22, 2022*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '10, 5¢; '15, (16¢); '17, (5¢); gains (loss) on discontinued ops.: '06, 1¢; '09, (1¢); '10, 1¢. '20 EPS don't sum due to rounding. Next earnings report due July 28. (B) Div'ds historically paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '21: $2738 mill., $4.42/sh. (D) In mill. (E) Rate base: Varies. Rate allowed on com. eq. (blended): 9.6%; earned on avg. com. eq., '21: 10.6%. Regulatory Climate: Average.

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

CASE: UE 399
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1900

Rebuttal Testimony

August 11, 2022

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

A. My name is John L. Fox. I am a Senior Financial Analyst employed in the Energy Rates, Finance, and Audit 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. I provided Staff/200-209.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize PacifiCorp's proposed revenue requirement changes, present the changes in revenue requirement associated with Staff's rebuttal position, and discuss the proposed amortization of deferred amounts in a separate tariff.

Q. Did you prepare additional exhibits in rebuttal?

A. No.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Summary of Findings and Recommendations 2
Overall Revenue Requirement... 3
Deferral Amortization 11

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. What is the change in revenue requirement recommended by Staff?

A. Staff proposes to reduce the Company's requested General Rate Case revenue requirement increase from $84.4 million to $31.2 million.

Q. Other than the overall revenue requirement, what specific adjustments did you propose in your opening testimony?

A. I proposed adjustments for interest synchronization, deferral amortization, escalation, OPUC fee rate, Wyoming Wind Tax, Carbon and Cholla land, blanket projects, and attestations.

Additionally, I provided a recommendation regarding the Oregon Corporate Activity tax which was not quantified in my testimony for which PacifiCorp proposed an adjustment in reply.

Q. Have any of the specific adjustments proposed in your opening testimony been resolved?

A. Yes, the Company's reply filing includes the appropriate adjustments for interest synchronization, OPUC fee rate, Wyoming wind tax amounts, and Oregon Corporate Activity Tax amounts.

The escalation, Carbon and Cholla land, blanket projects, attestation, and deferral amortization issues have yet to be fully resolved and are discussed further below.

OVERALL REVENUE REQUIREMENT

Q. What GRC price change (revenue requirement) is presented in PacifiCorp's reply testimony and initial filing?

A. The general rate case results presented in the reply filing indicate a revenue increase of $86,429,440 is necessary.[1] This is higher than the revenue increase of $84,399,290 presented in the initial filing.[2] Staff notes that these figures are the output of the Company's Jurisdictional Allocation Model (JAM) and provides the most appropriate starting point for Staff adjustments.[3]

Q. Please discuss how this change in the overall GRC revenue requirement is further elaborated in the Company's reply filing.

A. As discussed above, the Company's JAM model presents a revised revenue requirement of $86.4 million. Further, Staff review confirms this figure already reflects removal of $7.7 million deferral amortization included in the original filed GRC revenue increase.

Two tables are presented in the Company's opening testimony. The first adds back $7.4 million of deferral amortization stating an overall total revenue requirement plus amortization of $93.8 million.[4] The second table subtracts

[1] PAC/2002, Cheung/4.
[2] PAC/1002, Cheung/4.
[3] In UE 374, the Company's sur-rebuttal revenue requirement was $47.5 million, which was further revised to $46.3 million in the Company's closing brief. This figure was the starting point for commission adjustments as per Order No. 20-473 at 1. In other words, the Commission allowed revisions to the initial filing as proposed in testimony for purposes of tracking the changes in revenue requirement during the proceeding. We follow the same method here.
[4] PAC/1200, Steward/4.

($9.7) million to arrive at a requested price change of $76.7 million.[5] Both tables show a list of corrections and updates to the original filing.

Q. Please summarize Staff's understanding of how the various figures fit together (millions).

	Steward 1200/4	Cheung 2000/4
Revenue Requirement (FILED)	$ 84.4	$ 84.4
Corrections	(3.6)	(3.6)
Updates	5.6	5.6
Reply Revenue Requirement	86.4	86.4
Add Back: Deferral Amortization	7.4	7.7
Total Rev. Req. + Amort.	$ 93.8	94.1
Subtract: Deferral Amortization		(7.7)
Reduction from Reply Rev. Req.		(9.7)
Requested Price Change (REPLY)		$ 76.7

Q. What are Staff's thoughts regarding the two displays?

A. First, adding back the amortization adjustment, the Company's GRC reply request is the same as the original filing, $84.4 million.

Second, elsewhere in testimony the Company asserts a lower figure of $82.2 including the impact of Oregon Corporate Activity Tax (OCAT) into base rates.

Third, moving the deferral amortizations outside of base rates, the OCAT, the Company's reduction of $9.7 million, and the effects of the rate mitigation adjustment will continue to be complicating factors for the remaining pendency

[5] PAC/2000, Chung/4.

of the case. The parties will need to carefully track the effect of further changes.

Fourth, the Company displays co-mingle corrections and updates which are not in dispute with others that remain controversial (e.g., cost of debt, escalation, pensions, etc.).

Q. Does Staff accept the proposed corrections of ($3.6) million?

A. Yes. Staff agrees to accept the correction, as Staff's modeling confirms the ($1.3) million adjustment to correct the interest synchronization error in the initial filing.[6] Staff notes, however, that additional interest synchronization adjustments will be necessary to accommodate the capital structure which remains a contested issue.

Staff has agreed to accept the AMA replacement amortization[7] and Clean Fuels Program,[8] corrections of ($1.0) million and ($1.3) million, respectively.

Q. Please discuss the various revenue requirement updates proposed by the Company, a $5.6 million increase in total.[9]

A. Regarding the Cost of L/T Debt adjustment $7.0 million,[10] Staff's understanding is that parties are working to resolve this issue at the time of drafting this testimony.

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6 Staff/200, Fox/9, and PAC/2000, Cheung/6.
7 AWEC/100, Mullins/19 and PAC/2000, Cheung/6.
8 Staff/1600, Shierman/3 and PAC/2000, Cheung/6.
9 Although Staff discusses these adjustments rounded to the nearest $100 thousand as the Company does, Staff notes that more exact figures are to be used in the final revenue requirement.
10 PAC/2000, Cheung/4.

Regarding Present Revenues Update of $3.5 million,[11] Staff accepts the portion of this adjustment pertaining to the paperless bill credit and does not support or oppose the portion pertaining to Schedule 41.[12]

Regarding escalation factors, Staff continues to advocate for use of the All-Urban CPI as published by the Oregon Office of Economic Analysis.[13] In particular, Staff reiterates its recommended use of information sources that are fully available to the public rather than opaque, privately controlled ones. The publicly available sources can be verified, but the proprietary sources cannot be analyzed and directly compared to the components of the widely used CPI rate.[14]

On the subject of escalation, PacifiCorp asserts that "public accessibility and comparability does not necessitate greater accuracy and appropriateness".[15] Staff simply disagrees. The Commission's mandate "to represent the customers of any public utility" and "to protect such customers, and the public generally, from unjust and unreasonable exactions and practices"[16] necessitates a level of transparency which allows Staff to fully vet the calculation of escalation factors in future rate proceedings. The proprietary nature and opacity of the IHS Markit indices will not support this elemental staff review.

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[11] PAC/2000, Cheung/6.
[12] KWUA-OFBF/100, Reed/11 and PAC/2000, Cheung/6.
[13] Staff/200, Fox/30. Staff notes that the Company's $2.8 million reply increase based on the latest IHS Markit is nearly identical to the increase proposed by Staff in opening testimony based on the All-Urban CPI.
[14] Staff/200, Fox/33.
[15] PAC/2000, Cheung/31.
[16] ORS 757.040.

Regarding the Company's proposed $1.8 million increase for Pension Non-Service Expenses,[17] Staff rejects this adjustment as further discussed in the rebuttal testimony of Steve Storm.

Regarding the Company's proposed $900 thousand increase in TAM Revenue Sensitive costs, Staff notes that a full settlement of all issues is pending in the UE 400 docket[18] and the Company's reply filing adjusts to the UE 400 reply filing.[19] Accordingly, this adjustment will need to be revised to reflect the final TAM revenue.

Regarding the Company's proposed $700 thousand increase for Wages & Benefits,[20] Staff rejects this adjustment as further discussed in the rebuttal testimony of Heather Cohen.

As noted above, and further discussed below, the Company has removed $7.7 million of deferral amortization from its revenue requirement model to be recovered on a separate tariff, as was recommended by Staff.

Regarding the ($2.1) million Jurisdictional Loads Update, Staff has agreed to this adjustment[21] based on the Company's reply testimony.[22] Staff notes that the change in Utah Jurisdictional load has caused the various rate

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[17] PAC/2000, Cheung/20.
[18] See *In the Matter of PACIFICORP, dba PACIFIC POWER, Transition Adjustment Mechanism,* Docket No. UE 400, PacifiCorp's Motion to Modify Procedural Schedule filed 7/14/2022.
[19] PAC/2000, Cheung/40.
[20] PAC/2000, Cheung/19.
[21] Inclusive of the Company's rejection of AWEC's Utah Schedule 34 and DSM adjustments as further discussed in the rebuttal testimony of Dr. Curtis Dlouhy.
[22] PAC/2000, Cheung/3.

base allocation factors[23] to decrease, which is the primary cause of the $20 million decrease in allocated electric plant in service in the reply filing.[24]

Regarding the ($500) thousand Fuel Stock Update, Staff supports this adjustment.[25]

Regarding the ($400) thousand Remove Merwin In-Lieu, Staff supports this adjustment as calculated by the Company.[26]

Regarding the ($300) thousand OCAT & Metro BIT, Staff supports this adjustment as calculated by the Company.[27]

Q. Does Staff's rebuttal modeling include the ($9.7) million reduction from revenue requirement?

A. No. This adjustment was necessary in reply as the Company has rejected nearly all adjustments proposed by the parties resulting in a reply revenue requirement exceeding the original filing.[28] As Staff continues to advocate for a different capital structure, lower return on equity, and further reductions in operating expenses, Staff's recommended rebuttal revenue requirement is well below the amount proposed in the Company's initial filing.

Q. What additional adjustments are proposed by Staff?

A. Staff proposes the following adjustments for the Company's $86.4 million reply revenue requirement.

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[23] PAC/1002, Cheung/294 compared to PAC/2002, Cheung/195.
[24] PAC/1002, Cheung/3 compared to PAC/2002, Cheung/3.
[25] PAC/1900, Owen/10 and PAC/2000, Cheung/60.
[26] PAC/2000, Cheung/74.
[27] PAC/2000, Cheung/48.
[28] PAC/1200, Steward/5. Staff notes that the Company also states that "any adjustments the Commission adopts should be applied to the $86.4 million request."

PacifiCorp
STAFF ISSUE SUMMARY
Twelve Months Ended December 31, 2023
($000)

Non-NPC Related Price Change (excludes TAM)							**$86,429**
Testimony	**Issue No.**	**Staff**	**Staff Adjustments**	**Revenue**	**Expense**	**Rate Base**	**Revenue Requirement Effect**
	1800-1	Muldoon	Capital Structure				(6,561)
	1800-2	Muldoon	Return on Equity				(17,204)
	2600-2	Fjeldheim	Adjust uncollectable rate to 0.336%				(106)
	1900-1	Fox	TAM-Related Rev. Sensitive Expense	$0	($120)		($170)
	1900-2	Fox	Capitation Adjustment	-	-	$0	-
	1900-3	Fox	Interest Sync.	-	-	$0	(1,494)
	1900-4	Fox	Escalation	-	115	-	119
	1900-5	Fox	Land	-	-	(345)	(30)
	2300-1	Cohen	Wages & Salaries Adj.	-	(2,184)	(1,823)	(2,416)
	2600-1	Fjeldheim	Customer Accounts	-	(3,285)	-	(3,393)
	2600-2	Fjeldheim	Uncollectable Expense	-	(2,046)	-	(2,114)
	2600-3	Fjeldheim	Legal Fees & Expenses	-	-	($2,900)	(253)
	2700-1	Jent	Advertising	-	(91)	-	(94)
	2700-2	Jent	Medical Insurance	-	-	-	-
	2700-3	Jent	Non-Med Insurance & Risk	-	(3,121)	-	(3,224)
	2800	Moore	Wildfire / Vegitation Mgmt.	-	(6,568)	-	(6,785)
	2900	Peng	Depreciation Expense	-	(1,070)	-	(1,106)
	3000-1	Rossow	Memberships & Subscriptions	-	(32)	-	(33)
	3000-2	Rossow	Meals, Entertainment, and Awards	-	(6)	$0	(7)
	2500-1	Storm	Pension Expense	-	(3,581)	-	(3,699)
	2500-2	Storm	WMVM Mechanism	-	(6,400)	$0	(6,611)

Total Staff Adjustments	**$ (55,180)**
Staff-Calculated Revenue Requirements Change (Base Rates):	**$31,249**

Q. Regarding your issues labeled 1900-1 through 1900-5 above, please elaborate.

A. Regarding the TAM revenue sensitive adjustment, the $170 thousand adjustment is necessary to match the Company's JAM model due to how the Staff model calculates the revenue requirement.

Regarding capitation, this adjustment is zero because Staff's proposed revenue requirement is more than $9.7 million below the initial filing as discussed above.

Regarding interest synchronization, this is the additional amount necessary due to Staff's positions regarding capital structure as discussed above.

Regarding escalation, this adjustment increases the Company's reply escalation adjustment to match Staff's opening testimony.[29]

Regarding land, Staff accepts the Company's correction regarding the Oregon allocated portion of the Carbon and Cholla land.[30] However, the remaining Oregon allocated amount must be removed as they are no longer used and useful.[31]

Q. Have you changed your recommendations regarding blanket projects and attestations?

A No. My recommendation remains the same as discussed in my opening testimony.[32]

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[29] Staff/200, Fox/30-35.
[30] PAC/2000, Cheung/60.
[31] Staff/200, Fox/57.
[32] Staff/200, Fox/58-66.

DEFERRAL AMORTIZATION

Q. Please review Staff's opening testimony position regarding deferral amortization.

A. PacifiCorp proposed the following amortizations within base rates in its initial filing.

Deferral Docket	Deferral Details	December 2022 Balance	Amortization Period	Annual Amortization	Interest Rate
UM 1964 Trans. Electrification	Cheung, 1002/245	$ 2,839,892	3 years	$ 974,165	1.82%
UM 2134 Cedar Springs 2	Cheung, 1002/275	$ 748,136	3 years	$ 256,632	1.82%
UM 2142 Cholla Taxes	Cheung, 1002/272	$ 639,589	3 years	$ 219,065	1.82%
UM 2167 Prior Mtn. REC's	Cheung, 1002/246	[redacted]			
UM 2186 TB Flats	Cheung, 1002/278	$ 17,900,662	3 years	$ 6,140,445	1.82%
Proposed Amortization				$ 7,465,401	

In response, Staff proposed a lower amortization amount for Cedar Springs 2 as well as amortization of the COVID-19 and Fly Ash deferrals.[33]

Deferral Docket	December 2022 Balance	Amortization Period	Annual Amortization	Interest Rate
UM 1964 Trans. Electrification	$ 2,839,892	3 years	$ 974,165	1.82%
UM 2134 Cedar Springs 2	$ 609,342	3 years	$ 208,705	1.82%
UM 2142 Cholla Taxes	$ 639,589	3 years	$ 219,065	1.82%
UM 2167 Prior Mtn. REC's	[redacted]			
UM 2186 TB Flats	$ 17,900,662	3 years	$ 6,140,445	1.82%
UM 2063 COVID-19	$ 17,010,221	3 years	$ 5,826,155	1.82%
UM 2201 Fly Ash	$ (3,570,321)	3 years	$ (1,222,867)	1.82%
Proposed Amortization			$ 12,020,761	

Q. In reply, the Company notes that the proposed amortizations appear to not have been excluded from Staff's opening revenue requirement model.[34] How do you respond?

[33] `Staff/200, Fox/28-29.
[34] `PAC/2000, Cheung/52.

A. As illustrated in the revenue requirement discussion above, moving amortization to a separate tariff complicates comparison of the bottom line change in revenue requirement amongst the various filings in this case. Accordingly, and since Staff was making an initial proposal, Staff chose to leave the amortization in its opening model.

As the Company as has accepted Staff's proposal and removed the amortization from its JAM model, Staff is making the same change in its rebuttal revenue model.

Q. Please discuss the amortization proposal in the Company's reply filing.

A. The Company proposes corrections and adjustment of the Cedar Springs 2 and COVID-19 deferrals,[35] proposes a longer deferral period of 4 years[36] for the COVID-19 deferral, and rejects amortization of the Fly Ash deferral asserting that it ought to be absorbed in regulatory lag.[37]

Deferral Docket	Deferral Details	December 2022 Balance	Amortization Period	Annual Amortization	Interest Rate
UM 1964 Trans. Electrification	Cheung, 2004/2	$ 2,839,892	3 years	$ 974,165	1.82%
UM 2134 Cedar Springs 2	Cheung, 2004/3	$ 681,475	3 years	$ 233,766	1.82%
UM 2142 Cholla Taxes	Cheung, 2004/6	$ 639,589	3 years	$ 219,065	1.82%
UM 2167 Prior Mtn. REC's	Cheung, 2004/5	[redacted]			
UM 2186 TB Flats	Cheung, 2004/4	$ 17,900,662	3 years	$ 6,140,445	1.82%
UM 2063 COVID-19	Cheung, 2004/7	$ 17,887,722	4 years	$ 4,643,594	1.82%
Proposed Amortization				$ 12,086,129	

Q. Does Staff accept the corrections, adjustments, and longer amortization period proposed by the Company?

35 PAC/2000, Cheung/52-55.
36 PAC/2000, Cheung/55.
37 PAC/2000, Cheung/55-56.

A. Yes. Regarding amortization, in Staff's view a recovery period of four years is reasonable to prevent "rate shock" in the overall context of this case.

Q. Does Staff continue to support amortization of AWEC's Fly Ash deferral?

A. Yes. Staff is troubled by the contemporaneous nature of the new fly ash sales agreement overlapping with the conclusion of the UE 374 case. As discussed in Staff Exhibit 209, AWEC states that PacifiCorp entered into the new contract in October 2020. The Company's brief, filed on October 19, 2020, proposed additional revenue requirement adjustments[38]. A material increase in fly ash revenues, which was a known and measurable change at that time, could have also been included. Reasonable minds can differ about rate case process and when the parties should eschew further adjustments. However, in Staff's view, AWEC's deferral application ought not to be dismissed as lost to regulatory lag without further consideration by the Commission.

Q. Please summarize Staff's amortization recommendation at this time.

A. Staff recommends adoption of the Company's proposal changes with amortization of the Fly Ash deferral over three years.

[38] See In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision, Docket No. UE 374, PacifiCorp's Closing Brief, Filed 10/19/2020 at 1.

Deferral Docket	December 2022 Balance	Amortization Period	Annual Amortization	Interest Rate
UM 1964 Trans. Electrification	$ 2,839,892	3 years	$ 974,165	1.82%
UM 2134 Cedar Springs 2	$ 681,475	3 years	$ 233,766	1.82%
UM 2142 Cholla Taxes	$ 639,589	3 years	$ 219,065	1.82%
UM 2167 Prior Mtn. REC's	[redacted]			
UM 2186 TB Flats	$ 17,900,662	3 years	$ 6,140,445	1.82%
UM 2063 COVID-19	$ 17,887,722	4 years	$ 4,643,594	1.82%
UM 2201 Fly Ash	$ (3,570,321)	3 years	$ (1,222,867)	1.82%
Proposed Amortization			$ 10,863,262	

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 399
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 2000

Rebuttal Testimony

August 11, 2022

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

A. My name is Rose Anderson. I am a Senior Economist employed in the Energy Resources and Planning 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. I provided Opening Testimony in Exhibit Staff/300.

Q. What is the purpose of your rebuttal testimony?

A. I discuss depreciation end dates and exit orders for coal units, as well as the need for a coal removal methodology.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Coal Depreciation and Exit Order Changes..................................... 2
Issue 2. Removing Coal from Rates 6

ISSUE 1. COAL DEPRECIATION AND EXIT ORDER CHANGES

Q. Please summarize your position on PacifiCorp's proposed coal depreciation and exit order changes from your Opening Testimony.

A. In Opening Testimony, I supported each of PacifiCorp's recommendations for changes to depreciation end dates and exit order modifications. This included a change to the Jim Bridger Unit 1 Exit Order to specify that it applies only to coal-fueled operations at that unit, as well as the following depreciation dates for the Craig, Hayden, and Colstrip units:

Coal Plant/Unit	Oregon Depreciable Life[27]	Oregon Exit Orders[28]	2021 IRP Retirement[29]
Colstrip 3-4	2027	2027	2025
Craig 2	2026	2026	2028
Hayden 1	2023	N/A	2028
Hayden 2	2023	N/A	2027
Jim Bridger 1	2023	2023	Convert to Gas
Jim Bridger 2	2025	N/A	Convert to Gas

I also recommended that PacifiCorp should notify the Commission as soon as it becomes aware of any delay in the gas conversion at Jim Bridger Unit 1, to allow the Commission to address any potential complications that could result from the unit continuing coal-fired operations after the unit's Exit Date.

Q. Did other parties submit testimony on the proposed depreciation date or exit order changes proposed by the Company?

A. Yes. Alliance of Western Energy Consumers (AWEC recommends extending the depreciable life of Jim Bridger 1 and 2 until 2038 to reflect the decision to convert these units to gas. Additionally, AWEC writes in Opening Testimony that the Colstrip depreciation end date should be kept at 2027 instead of moving it to 2025 in order to reduce rates in the near term. Finally, AWEC supports the Company's proposed depreciation dates for Hayden and Craig units.

Q. What is PacifiCorp's reply to AWEC's recommendations on depreciation dates?

A. In Reply Testimony, PacifiCorp responds to AWEC's recommendation to extend the depreciable lives of Bridger 1 and 2, stating that this recommendation is "constructive" and that the Company is willing to discuss it. The Company notes, however, that the recommendation "may be premature" until "the Commission has determined that conversion is prudent for Oregon customers."[1]

PacifiCorp also argues that the Colstrip date should be moved to 2025 and not kept at 2027, stating, "To avoid potential increased rate pressure in the future or stranded investment, the depreciable life of Colstrip should match its most likely retirement date."[2]

Q. What is your position on AWEC's recommendations?

A. I support AWEC's recommendation to extend the depreciable lives of Jim Bridger 1 and 2 to reflect their conversion to gas. This recommendation could help reduce rate impacts to customers in the near term and better align

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[1] PAC/1200, Steward/25.
[2] PAC/1200, Steward/25.

rate recovery with the useful life of the units. However, this would require the careful separation of the plant capital costs into: a) parts that are still involved in coal operations and b) parts that are exclusively used for gas operations. Any part that is still involved in coal operations at Units 3 and 4 after gas conversion should be depreciated by end of the units' current depreciable lives in Oregon.

Assuming there can be reasonable certainty that Jim Bridger Units 1 and 2 will be converted to gas, the depreciable lives of these units could be moved to a later date to reduce rate pressure in this rate case. This would be consistent with the requirements of 2016's Senate Bill (SB) 1547, because it would not result in any coal-fired resource being included in Oregon rates after 2030.[3]

The Commission has indicated that it finds PacifiCorp's plan to convert Units 1 and 2 to gas to be reasonable by acknowledging the gas conversion action item in the 2021 PacifiCorp IRP, where PacifiCorp's analysis showed that converting these units to gas would save ratepayers $469 million over 20 years.[4] Importantly, whether the Commission ultimately finds the gas conversion to be prudent or not, the investment in the existing infrastructure at Units 1 and 2 was determined to be prudent at the time the plant began commercial operation. Even though prudency was determined based on an expectation of coal-fired operations at those units, each unit would cease to be

[3] SB 1547, Section 1(2), Oregon Revised Statute (ORS) 757.518(2).
[4] *In the Matter of PacifiCorp 2021 Integrated Resource Plan,* Docket LC 77, Page 269 September 1, 2021.

a "coal-fired resource" for purposes of SB 1547 once it was converted to gas.[5] Customers could continue to pay for the depreciation of the units through 2038. However, moving the depreciable lives later than 2030 may not be advisable because of the requirements of HB 2021 to reduce Oregon-allocated emissions to 80 percent below baseline emissions by 2030.

I do not support AWEC's recommendation to keep the depreciable life of Colstrip until 2027. The 2021 PacifiCorp IRP identified 2025 as the optimal retirement/exit date of Colstrip units 3 and 4, and AWEC has introduced no new information to suggest that a later exit date would reduce system costs. Keeping a 2027 depreciation end date could cause difficulties and potential rate shock if PacifiCorp exits the units in 2025.

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[5] SB 1547, Section 1(1)(b)(A), ORS 757.518(1)(b)(A): "'Coal-fired resource' means a facility that uses coal-fired generating units, or that uses units fired in whole or in part by coal as feedstock, to generate electricity."

ISSUE 2. REMOVING COAL FROM RATES

Q. What was your position in Direct Testimony regarding removing coal from rates?

A. In my Direct (Opening) Testimony, I concurred with PacifiCorp that a mechanism to remove coal from Oregon rates can be decided in Docket No. UM 2183 and does not need to be decided in this rate case.

Q. Did any other party write about removing coal from Oregon rates in Reply Testimony?

A. Yes, Citizens' Utility Board (CUB) argued that a method to remove coal from Oregon rates needs to be decided before the end of 2023 because of the closure of a coal unit at the end of 2023. CUB argued that coal removal from rates needs to be done promptly because the Company agreed to do so in the 2020 Multistate Protocol (MSP), and because it will eliminate regulatory lag for retiring coal plants, establishing symmetry with the elimination of regulatory lag for new renewable resources in the Renewable Adjustment Clause.

Q. Do you agree that a coal removal method needs to be decided before the end of 2023?

A. Yes, unless the depreciation end date for Jim Bridger Unit 1 can be extended due to its conversion to natural gas. This would provide two additional years to decide on a coal removal methodology.

Q. What if the depreciation end date for Jim Bridger Unit 1 is not extended?

A. If the depreciation end date for Jim Bridger Unit 1 is not extended, then a coal removal method will need to be decided by December 31, 2023. Staff agrees with CUB's statement putting PacifiCorp on notice that, before the first coal depreciation schedule is complete, a method to timely remove coal depreciation from Oregon rates will need to be established.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 399
WITNESS: RYAN BAIN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2100

Rebuttal Testimony

August 11, 2022

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

A. My name is Ryan Bain. I am a Senior Economist 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.

Q. What is the purpose of your testimony?

A. To present Staff's response to various issues raised regarding PacifiCorp's Load Forecast in UE 399.

Q. Did you prepare any exhibits for this rebuttal testimony?

A. No.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1 - Schedule 41 Load Forecast 2
Issue 2 - Utah DSM in 2020 Protocol 4

ISSUE 1 - SCHEDULE 41 LOAD FORECAST

Q. What issue was raised by KWUA-OFBF witness Mr. Reed concerning the Schedule 41 irrigation annual temperature normalized load for the Calendar Year 2023 Rate Period?

A. Mr. Reed identified an unusually large test year forecast of 265,565 MWh.[1]

Q. What was PacifiCorp's (the Company's) response?

A. The Company identified the cause of the unusually large forecast as the result of anomalous 2020 load. Because the Company utilizes the most recent year (or two) of load to apportion costs from the irrigation class to the specific irrigation rate schedules, the anomaly resulted in higher costs being allocated to Schedule 41.

Q. How does the Company propose to correct for this issue?

A. The Company proposed to correct for this issue by expanding the number of years used to apportion the class level forecast by using rate schedule actual data over a four-year period (April 2017 to March 2021) instead of the original one-year period (April 2020 to March 2021).[2] Using these values the test year forecast for Schedule 41 is reduced to 234,973 MWh.

Q. Does Staff have concerns with the proposed correction?

A. Staff is satisfied with this correction as it proposes to minimize the strong influence of one year's worth of anomalous load data by employing a reasonable moving average of several recent years' worth of data. Staff

[1] PAC/1800, Elder/1, Lines 16-17.
[2] PAC/1800, Elder/2, Lines 9-11.

reviewed the updated data and believes that the multi-year average better characterizes load expectations for this schedule. Staff also examined the load data based on the Company's response to Staff DR No. 110. Staff notes that Schedule 48's load dropped by 44 percent during 2020 from its previous five-year average. Staff agrees with the Company that this data point is not representative of the normal load for this schedule. Utilizing the average load for Schedule 48 over the previous four years increases the amount allocated to Schedule 48 and reduces the amount allocated to Schedule 41 in a reasonable manner.

ISSUE 2 - UTAH DSM IN 2020 PROTOCOL

Q. What issues does AWEC raise regarding Utah DSM programs and their inclusion in Utah's jurisdictional load-based dynamic allocation factors?

A. AWEC claims that Utah DSM programs are already included in PacifiCorp's load forecast, and therefore making an additional adjustment to the loads for use in determining Utah's dynamic load-based allocation factor is unnecessary. AWEC further states that the DSM programs provide no benefit to Oregon customers and results in the Company's forecast for DSM programs to be overvalued in the coincident peak forecast.

Q. What is the Company's response?

A. The Company cites their treatment of Utah DSM programs in the coincident peak forecast as being consistent with Section 3.1.2.1 of the 2020 Protocol. They additionally offer that this same treatment was used and approved by the OPUC in the Company's last Oregon rate case, docket UE 374.[3] Further, the Company describes its process avoided any double counting of the impacts of the DSM program by noting that the historic data utilized as an input to the peak load forecast has any curtailments from Class 1 DSM programs in Utah removed. Then once the peak forecast is performed the DSM curtailments are added back in for allocation purposes. Finally, the Company states that AWEC has misinterpreted the Company's response to DR 063 regarding the DSM adjustment and the implications as to the size.

[3] PAC/2000, Cheung/87, Lines 19-21.

Q. What is Staff's recommendation?

A. Staff surmises that the Company removes DSM impacts from its historic data in order to identify a peak load forecast without conflation of DSM impacts on actuals. If the Company were to include the DSM curtailments in its load forecast the resulting forecast may be similar but would not allow the DSM program to directly address the peak for planning purposes but would instead include all the times the program had been called on. This would potentially lead to improper assumptions about load/resource balancing calculations. Staff has also reviewed the Company's response to AWEC DR 63 and DR 66 and believes that the 250 MW number cited by AWEC may be overstating the capacity. Staff finds that the Company has properly estimated the impacts of the DSM program and complied with the 2020 protocol.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 399
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2200

Rebuttal Testimony

August 11, 2022

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

A. My name is Madison Bolton. I am a utility analyst employed in the Strategy & 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. I provided Opening Testimony regarding PacifiCorp's (PAC or the Company) proposed Accelerated Commitment Tariff (ACT).

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to review other parties' positions and make recommendations on the Company's proposed voluntary renewable energy tariff (VRET) in Schedule 273.

Q. Did you prepare an exhibit for this rebuttal testimony?

A. Yes. I prepared Exhibit Staff/2202, consisting of 2 pages. This exhibit contains PacifiCorp responses to Staff data requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. VRET Procurement Cap 2
Issue 2. Customer Supply Option 5
Issue 3. Energy and Capacity Credit 7
Issue 4. Subscriber Mismatch Fee and Administrative Fee 9
Issue 5. Competitive Bidding Rules 12
Issue 6. Compliance with VRET Condition 7 13
Issue 7. Percentage-Based Facility Output 15
Issue 8. Unbundled RECs 17
Issue 9. Direct Access Eligibility 19

ISSUE 1. VRET PROCUREMENT CAP

Q. What parties provided positions on PacifiCorp's VRET procurement cap?

A. Oregon Citizens' Utility Board (CUB) witness William Gehrke supports keeping the procurement cap at 175 average megawatts (aMW) at this time.[1] Northwest and Intermountain Power Producers Coalition (NIPPC) witness Spencer Gray provides that the cap should remain at 175 aMW, but if a separate cap is necessary, it should be attributed to a customer supplied option (CSO).[2] Vitesse, LLC (Vitesse) witness Bradley Cebulko proposes allowing a separate 175 aMW cap for new, incremental load from existing or new customers.[3] PacifiCorp maintains its original proposal of keeping the cap at 175 aMW, as outlined in Condition 4 of the Commission's VRET principles in UM 1953[4]

Q. What reasoning do parties provide to increase the cap?

A. Mr. Cebulko states that PacifiCorp's ACT meets the same conditions that Portland General Electric Company (PGE) met when the Commission allowed an expansion of the Green Energy Affinity Rider (GEAR) in Order 21-091, specifically, the program "has been designed to minimize impacts to the competitive market and reduce the risk exposure to non-participating cost-of-service customers associated with the increase."[5]

1 CUB/200, Gehrke/34.
2 NIPPC/100, Gray/8-9.
3 Vitesse/100, Cebulko/19.
4 Docket No. UM 1953, Order No. 21-091 at 11.
5 Id. at 9.

Q. What is Staff's recommendation?

A. With the ACT being a new program and lacking historical data to evaluate whether cost shifting is occurring, Staff recommends that the Commission use a case-by-case approach to evaluate proposed expansions of the cap. Vitesse outlines such an approach as an alternative to a blanket cap expansion[6], explaining that a new load customer could seek a waiver based on the criteria in Order 18-341[7]. However, Vitesse notes that this process would add uncertainty for the customer that may dissuade them from seeking a VRET resource in the state of Oregon.

Staff understands that a case-by-case approach is not the most convenient for a potential customer's business planning and suggests that adding a time-limited petition pathway based on the criteria in Order 18-341 could allow the Commission to reach a decision on the expansion in a uniform and clear way for each request.

Staff notes that the emergence of community-wide green tariffs as allowed in HB 2021 could also provide significant changes to balancing the risks associated with a large number of residential customers on green tariff schedules versus ensuring that large, non-residential customers can obtain renewable energy as fairly as residential customers. These implications could change how VRET caps are set in the future or influence the process for expansion.

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6 Vitesse/100, Cebulko/21.
7 Docket No AR 614, Order No. 18-34.

Q. Do NIPPC and PacifiCorp support a case-by-case approach for cap expansion?

A. Yes. PacifiCorp explains that a case-by-case approach would help the Commission and the Company be able to better identify risks and allow the Commission time to better evaluate a detailed expansion proposal. NIPPC states that it does not oppose an expedited mechanism to increase the cap, but only if that same mechanism is available for PacifiCorp's direct access program. Staff notes that direct access program caps are being debated as part of UM 2024, and Staff recommends addressing changes to direct access programs in that docket, not UE 399.

ISSUE 2. CUSTOMER SUPPLY OPTION

Q. What are the parties' positions on including a Customer Supply Option (CSO) in the VRET?

A. Vitesse and NIPPC both support including a CSO, based on its ability to better meet certain customers unique needs[8] and that the ACT structure protects against cost-shifts to non-participants, similar to the design of PGE's GEAR program.[9] PacifiCorp states that a CSO option was considered when designing the VRET, but concerns about a higher risk for cost shifts prompted the Company to not include it. PacifiCorp states that because a participant and developer would choose the location of the resource in a CSO, it could generate higher network upgrade costs that would be recovered from all users of the transmission system[10].

In Staff's Data Request (DR) No. 598, I ask whether the Company could identify cost-of-service project-driven network upgrade costs that are in excess of the system benefits the upgrades provide and allocate the excess costs to the VRET customer. PacifiCorp responded that this specific kind of analysis could only happen on a case-by-case basis if at all and the Company would have difficulty identifying all of the costs and benefits related to reliability.[11] PacifiCorp states that the Company would be open to discussing a CSO with

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8 Vitesse/100, Cebulko/26.
9 NIPPC/100, Gray/8.
10 PAC/1700, McVee/7.
11 Staff/2202, Bolton/1.

customers on a case-by-case basis, which would result in a better analysis of the specific project and cost-shifting concerns.

Q. What is Staff's recommendation?

A. Staff maintains that a CSO is an important offering in the ACT that could provide sophisticated customers with a pathway that better fits their needs and advances renewable energy deployment. Staff understands the Company's concerns that transmission upgrade costs due to siting could cause cost shifting and recommends that further discussion between parties takes place to determine whether there is a mitigation strategy and to better identify the specific risks. Staff continues to recommend that a CSO be included in the ACT at this time. Staff would also be amenable to a case-by-case process at first which could allow for a more thorough review of the cost shifting concerns raised by PacifiCorp.

ISSUE 3. ENERGY AND CAPACITY CREDIT

Q. What are the positions of the various parties regarding the energy and capacity credit calculation in the VRET?

A. NIPPC proposes the ACT include language specifying that the calculation will have a floor to prevent the credit from resulting in the net reduction of energy costs to participants below the costs incurred by non-participating customers[12]. PacifiCorp agreed with this mechanism, noting it is a key component of mitigating securities compliance issues associated with participants.[13] However, PacifiCorp also suggests that either leaving the tariff language less specific or using the credit value to balance the risks between participants, non-participants, and the utility in certain circumstances may provide flexibility to enhance small-scale renewable energy to comply with state policy.[14] The Company explains this suggestion further in the response to Staff DR 601.[15]

Q. What is Staff's recommendation?

A. Staff continues to recommend that the tariff include a description that the energy and capacity credit be calculated so that the credit cannot exceed the participant's costs. Staff believes this detail is an important safeguard that protects non-participants. Staff is amenable to the possibility of allowing adjustments to the balance of risks, potentially using the credit value, but a

12 NIPPC/100, Gray/4.
13 PAC/1700, McVee/9.
14 Id, 10.
15 Staff/2202, Bolton/2.

specific proposal would need to be submitted with an opportunity for Commission review.

ISSUE 4. SUBSCRIBER MISMATCH FEE AND ADMINISTRATIVE FEE

Q. Please describe the subscriber mismatch fee and the administrative fee.

A. The Company has included a subscriber mismatch fee to collect revenues from the participant during their contract term to account for certain above market costs over the entire length of the power purchase agreement (PPA). For example, if a participant subscribes to the program for a duration shorter than the PPA, the Company will collect the above market costs for the resource that exist over the full term of the contract, spread across the years that the participant has subscribed. In the case of utility-owned resources, the full term would be the life of the facility since there is not a PPA contract.

The administrative fee is included to account for the administrative costs incurred by operating the program. Without this fee, non-participating COS customers would be paying to operate the program instead of participants. An administrative fee may account for costs related to information technology, marketing, accounting, human resources, and facilities that are directly or indirectly impacted by the existence of the ACT.

Q. What are the positions of the various parties on the subscriber mismatch fee?

A. In Staff's opening testimony, I expressed concern with the subscriber mismatch fee for company-owned resources providing accelerated cost recovery to PacifiCorp without the participant receiving any additional benefits. If the mismatch fee revenues are earning interest at the Oregon Public Utility

Commission’s rate for deferred accounts, then the Company is effectively receiving revenues that are accelerating the cost recovery of the resource it owns. Staff suggests that factoring in the interest revenues to reduce the mismatch fee for participants may be a solution to prevent one-sided, accelerated recovery.

Q. What are the positions of the parties on the administrative fee?

A. CUB recommends that the administrative fee revenues be passed back to non-participating customers through the Transition Adjustment Mechanism (TAM). PacifiCorp explains that doing so would create administrative burden and the structure of the Power Cost Adjustment Mechanism (PCAM) could cause COS customers to pay some of the costs to operate the ACT program or could cause them to receive a credit without assuming a portion of the risks. Additionally, PacifiCorp does not incorporate other customer program costs in the TAM. PacifiCorp suggests using a deferral mechanism to credit administrative fee revenues back to cost-of-service customers, including the participants with COS schedules.

Q. What is Staff’s recommendation?

A. Staff questions whether the administrative fee revenues need to be credited back to COS customers. Instead, Staff recommends that the Company identify all the administrative costs that the program causes and apply loadings. This separate accounting should recover the administrative costs directly from participants that the program incurs. This way, COS customers are not paying for administrative costs and there is no need for the administrative burden of a deferral account, or a TAM forecast and true-up.

ISSUE 5. COMPETITIVE BIDDING RULES

Q. What are the positions of the parties on the competitive bidding rules and using the existing procurement process in the 2021 Integrated Resource Plan, the 2022 All-Source (AS) Request for Proposals (RFP)?

A. Vitesse states that PacifiCorp can use the results of its 2022AS RFP to identify resources for the VRET. Additionally, Vitesse explains that issuing a second RFP for identifying ACT resources would be administratively burdensome without gaining significant benefits[16] NIPPC maintains that the competitive bidding rules apply to the ACT and PacifiCorp must seek waivers when the size and circumstances of a resource require it.[17] This is a similar expectation to PGE's GEAR as defined in Order No. 19-213.

Q. Does Staff agree with Vitesse and PacifiCorp's positions?

A. Yes. Staff agrees that the competitive bidding rules should apply unless a waiver is brought before the Commission. Staff also recommends that a waiver for each resource should be individually sought instead of requesting a blanket waiver. Additionally, Staff agrees that the 2022AS RFP can be used to identify resources, but as PacifiCorp notes[18], negotiations and Commission approvals would need to be completed prior to the bid validity date on November 21, 2023.

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[16] Vitesse/100, Cebulko/25.
[17] NIPPC/100, Gray/3.
[18] PAC/1700, McVee/14.

ISSUE 6. COMPLIANCE WITH VRET CONDITION 7

Q. What are the positions of the various parties on whether the ACT complies with the Commission's VRET Condition 7?

A. CUB explains that Condition 7, which requires that the Company share the return on a utility-owned VRET resource with ratepayers if ratepayer-funded assets are used to assist the voluntary renewable offering[19], has not been met because PacifiCorp has not provided an explanation on how it will share the return. NIPPC presents similar concerns, stating that the Commission should not approve a VRET where the utility reserves the right to explain accounting protections or alternative mechanisms for utility-owned resources and reiterates that the Company must meet Condition 7.[20]

Additionally, NIPPC explains that utility ownership for a resource incentivizes the Company to favor its own projects over third-party developers'. PacifiCorp disagrees, explaining (1) that the competitive bidding rules mitigate against this concern; (2) Condition 7 only applies in certain situations; (3) the parties' arguments do not show that non-participants are incurring costs to support the ACT program; and (4) that it is unfair to "disadvantage the utility without a showing that other cost-of-service customers are subsidizing service under the VRET."[21]

Q. What is Staff's recommendation?

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19 Docket No. UM 1953, Order No. 21-091 at 12.
20 NIPPC/100, Gray/10.
21 PAC/1700, McVee/16-17.

A. Staff maintains its original recommendation from opening testimony that PacifiCorp must submit a filing detailing accounting methods and safeguards prior to any consideration of using a utility-owned resource.[22] Until the Company submits such a filing, utility-ownership for VRET resources should not have a blanket or individual approval.

[22] Staff/500, Bolton/4.

ISSUE 7. PERCENTAGE-BASED FACILITY OUTPUT

Q. What is Vitesse's proposal regarding an option for percentage-based facility output generation?

A. Vitesse explains that PacifiCorp has only allowed program participants to sign up for a fixed delivery generation output equal to less than 100% of the output from a VRET resource. To mitigate risk for non-participants, PacifiCorp intends to allocate any RECs generated above the guaranteed generation delivery back to non-participants. Vitesse states that this causes the Company to assign 100 percent of the costs of the program to participants without assigning 100 percent of the benefits to participants. As a solution, Vitesse recommends including an option for customers with load of 1 aMW or above to take variable annual delivery as a percentage of the resource's output.[23] Vitesse argues this method would flow all benefits back to participants and would mitigate risks to non-participants caused by the fixed delivery method. PacifiCorp raised concerns about securities compliance if the fixed delivery method was not utilized when the customer commits to participating.

Additionally, PacifiCorp stated that the program would not be able to be offered without further analysis due to the compliance risk if the percentage-based delivery method is included. However, PacifiCorp explained that Vitesse's proposal could work if the Company could discuss the idea with

[23] Vitesse/100, Cebulko/31.

specific customers and a single entity was going to take the entire output of a resource.[24]

Q. What does Staff recommend?

A. Staff recommends that an option for a percentage delivery output be included in the ACT to assign costs and benefits more accurately, with a threshold of at least 1aMW for participation. Staff understands that a capacity threshold helps ensure this option is only utilized by large customers that can manage the risks associated with variable delivery output. Staff notes that this recommendation can change based on further analysis the Company provides on any risks a percentage output option poses to non-participants and the utility.

[24] PAC/1700, McVee/20.

ISSUE 8. UNBUNDLED RENEWABLE ENERGY CREDITS

Q. What does NIPPC propose regarding the use of unbundled RECs in the event of yearly under-generation?

A. NIPPC states that purchasing unbundled RECs to cover under-generation of a VRET resource should only be carried out in truly unforeseen or emergency situations, and that the language in Schedule 273 wrongly allows for purchasing unbundled RECs in any situation when a resource under-generates.[25] NIPPC also claims that PGE's GEAR program does not allow the utility to purchase unbundled RECs in any event. PacifiCorp argues that this assertion is false, demonstrating that the ACT language and PGE's GEAR tariff language are nearly identical regarding REC purchases covering under-generation. Staff agrees that both tariffs do not specify that bundled RECs must be purchased in the event of yearly under-generation.

Q. What is Staff's recommendation?

A. Staff suggests that PacifiCorp include language in the ACT stating that the Company will "make best efforts" to purchase bundled RECs in the event of under-generation. This language is similar to PGE's GEAR tariff that states "the Company, at the election of the Subscribing Customer, shall make reasonable efforts to procure a new resource on behalf of the Subscribing Customer…"[26]

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[25] NIPPC/100, Gray/7.

[26] PGE Schedule 55, Large Nonresidential Green Energy Affinity Rider (GEAR), Sheet No. 55-3.

While the language in PGE’s tariff is not referring to RECs specifically, it is similar to Staff’s proposed addition to PacifiCorp’s ACT in that it provides more accountability in non-emergency situations and when a bundled REC option is are available.

ISSUE 9. DIRECT ACCESS ELIGIBILITY

Q. What does NIPPC propose regarding Direct Access customer participation in the ACT?

A. NIPPC argues that the language in the ACT disqualifying Direct Access (DA) customers is discriminatory and creates artificial barriers to the competitive retail market. NIPPC notes that in PGE's GEAR program, QTS data systems was able to petition and take service in the GEAR program despite being a new-load DA customer.

NIPPC also states that the ACT's 30 kW threshold for participants creates market barriers and should be increased to at least 2 MW of billing over a 13-month period.[27]

PacifiCorp contends that the ACT is not discriminatory, as DA customers have the option to take service from an ESS to accomplish renewable energy goals. Additionally, the Company explains that using PGE's decision with QTS data systems should not be applied in this circumstance, stating that one utility's regulatory decisions should not introduce a, "blanket requirement for another utility".[28] Regarding matching the ACT's threshold to a 2 MW threshold, PacifiCorp states that the 2 MW threshold is only for large customers on Schedule 294, while other DA schedules exist that match the ACT's 30 kW threshold.[29]

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27 NIPPC/100, Gray/16.
28 PAC/1700, McVee/23.
29 Id.

Q. What does Staff recommend regarding DA participation in the ACT?

A. Staff does not recommend changes to the ACT language regarding DA participation at this time. First, PGE's waiver to allow QTS service in the GEAR was made after consideration of multiple factors such as resource selection and availability within the GEAR cap. Staff maintains that examining a specific customer's case provides more detail about cost shifts and risks rather than recommending a blanket approval for DA participation. Second, Staff understands that PGE's GEAR threshold is 30 kW and matches their Schedule 583 DA threshold. PAC's DA Schedule 728 threshold is also 30 kW, matching the ACT limit. Staff recommends not making changes to the current threshold language in the ACT, remaining consistent with the threshold in PGE's GEAR that has already been vetted by the Commission.

Additionally, regarding NIPPC's suggestion that certain DA program thresholds could be altered, Staff maintains that DA program caps and limits is currently under discussion in Docket No. UM 2024.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 399
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2201

Witness Qualifications Statement

August 11, 2022

WITNESS QUALIFICATIONS STATEMENT

NAME:	Madison Bolton
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst Utility Strategy & Integration Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	B.A. Carroll College, Helena, Montana Major: Biology, 2017 M.ENV. University of Colorado, Boulder, Colorado Specialization: Renewable and Sustainable Energy, 2020
EXPERIENCE:	Since September 2021, I have been employed by the Oregon Public Utility Commission. I currently hold the position of Utility Analyst 2 in the Utility Strategy and Integration Division From 2019 to 2020 I worked as a graduate research analyst at E Source where I conducted research for utility clientele on large non-residential energy consumers. Additionally, in 2020 I assisted Camus Energy in researching the feasibility of electric grid management software

CASE: UE 399
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2202

Exhibits in Support
Of Rebuttal Testimony

August 11, 2022

UE 399 / PacifiCorp
August 2, 2022
OPUC Data Request 598

OPUC Data Request 598

VRET CSO - Regarding PAC/1700 McVee/7, Lines 2-6[1], please explain whether the Company could identify cost of service project-driven network upgrade costs that are in excess of the system benefits they provide and allocate those excess costs to the VRET customer.

Response to OPUC Data Request 598

PacifiCorp objects to this data request to the extent it calls for speculation. Subject to and without waiving the foregoing objection, the Company states as follows:

Such an analysis depends heavily on how benefits are quantified, could only be contemplated on a case-by-case basis, if at all, and may change over time as the system usage changes. Accordingly, PacifiCorp would either need to look only at a snapshot of benefits or identify specific assumptions regarding future use. Network upgrades may provide additional capacity or provide for additional market access or dispatch, again immediately or in the future as the system evolves. Similarly, network upgrades may add to overall system reliability immediately, or in the future. Reliability benefits, however, are often more difficult to convert to a monetary benefit calculation because the benefit is the absence of a disruptive event, rather than tied to generation dispatch.

[1] ue399htb155155.pdf (state.or.us)

UE 399 / PacifiCorp
August 2, 2022
OPUC Data Request 601

OPUC Data Request 601

VRET Energy and Capacity Credit - Regarding PAC/1700 McVee/10, Lines 19-21, please describe why refraining from specifying a credit floor in the tariff would provide flexibility to enhance small-scale renewable generation in compliance with state policy.

Response to OPUC Data Request 601

It is generally assumed that small-scale renewable resources will be more costly than utility scale generation resources. Public Utility Commission of Oregon (OPUC) policy regarding small-scale renewable resources is also calculated on a capacity basis, therefore, PacifiCorp expects that its requirements may increase due to this program and the program may need some additional flexibility to continue to hold cost-of-service (COS) customers harmless. The proposed credit calculation accounts for the relative costs of a portfolio of resources that includes a voluntary renewable energy tariff (VRET) resource, and a portfolio of resources that does not include a VRET resource. Both of those portfolios would need to comply with Oregon's small-scale renewable generation requirement. Among the differences between the portfolios would be changes in the need for small-scale renewable resources, either directly if the VRET resource is 20 megawatt (MW) or less, or indirectly, if a VRET resource over 20 MW triggers a need for incremental small resources to maintain compliance. Because specifics of small-scale renewable resource compliance have not been finalized, and compliance does not begin until 2030, compliance costs for the small-scale renewable capacity requirement are uncertain at this time. The OPUC could potentially account for these factors that go beyond the current Integrated Resource Plan (IRP) portfolio modeling as part of the credit, and could provide additional incentives for small-scale renewable generation, for example.

CASE: UE 399
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2300

Rebuttal Testimony

August 11, 2022

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

A. My name is Heather Cohen. I am a Senior Utility Analyst employed in the Rates, Finance and Audit 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. I provided Staff/600.

Q. What is the purpose of your testimony?

A. The purpose of my rebuttal testimony is to provide Staff's review of PAC's Reply Testimony regarding salary, wages, incentives, and full-time equivalents (FTE).

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Wages, Salary, Incentives, and FTE 2
Table 1: 3-year model, UE 374 and UE 399 2
Figure 1: UE 374 & UE 399 Sharing Principle Formulas 4
Table 2: Staff's Union Escalation 5
Table 3: 4.2 - Wages and Eemployee Benfits Adjustment_CONF (sic) tab 4.2.3-4.2.5 CONF 6
Table 4: PAC Results of Operations - December 2021 7
Figure 2: Company's Wages and Employee Benefits Adjustment Initial and Reply 8
Figure 3: UE 399 SDR 92 Exempt Wages 2021-Test Year 10
Figure 4: PAC Results of Operation 2021 10

ISSUE 1. WAGES, SALARY, INCENTIVES, AND FTE

Q. What did Staff recommend as an adjustment to wages, salaries, incentives, and FTE in Opening Testimony?

A. In accordance with the wage and salary model, Staff recommended the following reductions: $4 thousand O&M and $2 thousand Rate Base to Officer salaries; $1.4 million O&M and $775 thousand rate base to incentives, reductions to overtime of $644 thousand O&M and $350 thousand rate base; and $1 million in rate base reduction to capitalized incentives.[1]

Q. What issues did the Company have with Staff's adjustments?

A. First, the Company takes issue with Staff's use of 2020 as a base year. The Wage and Salary model is a three-year model, therefore Staff used 2020 as a base year for a test year which essentially started in 2023 (12/31/22-12/31/23). In PAC's last rate case, UE 374, the Commission validated Staff's use of a base year of 2018 to escalate to the Company's 2021 test year: "We find Staff's use of 2018 calendar year data as a baseline is consistent with Commission practice to use a model base year three years prior to the test year."[2]

TABLE 1: 3-YEAR MODEL, UE 374 AND UE 399

Years	UE 374	UE 399
3 (Test Year)	2021	2023

1 See Staff/600/Cohen/16.
2 See Order 20-473 at 102.

2	2020	2022
1	2019	2021
Base Year	2018	2020

Q. Does the Company object to the way the wage and salary model makes adjustments?

A. PAC takes issue with the fact that even though Staff's projection is more than the Company's, the model chooses the lesser of the two options. The Company does not agree with the way the model makes piecemeal adjustments in discrete categories. For example, Staff's projection was ultimately more than the Company's except in the Officer category.

Q. Is this a new concept?

A. This is how the longstanding Wage and Salary model has always operated. 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 PAC's last general rate case (UE 374): **"IF"** formulas that state if Staff's projection is less than the Company's, a zero will be substituted.

<u>FIGURE 1: UE 374 & UE 399 SHARING PRINCIPLE FORMULAS[3]</u>

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. Currently, the United States is seeing its highest inflation in 40 years.[4] Moreover, a key measure of inflation, the Personal Consumption Expenditures price index, just rose to 6.8 percent for June while the U.S. annual consumer price index jumped 9.1 percent in the same month, the largest increase in four decades.[5] The Wage and Salary model used inflation rates of 4.7, 6.8, and 2.6 percent for 2021-2023, sourced from the Urban CPI June 2022 forecast. For contrast, the CPI rates used in PAC's last rate case were 1.8, 1.8, and 1.7 percent.[6]

Q. What did the Company say about the inflation factor Staff used?

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[3] See UE 374 Staff Exhibit 400 Issue 1 Wage and Salary Model CONF and Staff Exhibit 603 Wage and Salary Model CONF.

[4] Timiraos, Nick. Fed Lifts Rates by 0.75 Point Again. WSJ. 7/29/2022. Fed Raises Interest Rates by 0.75 Percentage Point (wsj.com).

[5] Minto, Rob. Headache for Biden as Key Inflation Index Rises to 40-Year High https://www.newsweek.com/headache-biden-key-inflation-index-rises-40-year-high-1729100; Mutikani, Lucia. U.S. Annual Consumer Inflation Posts Largest Increase since 1981. Reuters. 7/13/22. https://www.reuters.com/markets/us/gasoline-food-drive-us-consumer-prices-higher-june-2022-07-13/.

[6] See UE 374 Staff Exhibit 400 Issue 1 Wage and Salary Model CONF.

A. The Company argues that the CPI is inappropriately used on wages and that a wage inflator should be used instead.[7] However, the Commission has repeatedly validated the use of the CPI in the wage and salary model, most recently in the Company's last rate case, UE 374 where the order states:

> We will continue to rely upon the three-year model to establish non-union wages. As we have previously explained, this method incorporates actual market-based data by using actual historic wages as a starting point, but also ensures the utilities are incented to minimize labor costs by using the All-Urban CPI to escalate historic wages to the test year.[8]

Q. Does the Company object to the way Union wages and overtime was escalated?

A. Yes, the Company correctly points out that Staff's escalation was $5 million more than the Company's, instead of the $5 thousand written in Opening Testimony.

<u>TABLE 2: STAFF'S UNION ESCALATION</u>

[redacted]

[7] PAC/2000/Cheung/11.
[8] Order No. 01-787 at 39-40 as cited in Order No. 20-473 at 102.

First, Staff's estimate is still within one percent of the Company's projection for union wages. Second, Staff's projection is more generous than the Company's which invalidates any of the Company's objections that Staff has shortchanged union wages and salaries in its projection. Lastly, every other tab (eight in total) in Company's workbook "4.2 Wages and Eemployee Benefits Adjustment_Conf (sic)" is in whole numbers, except for one tab (Tab 4.2.3-4.2.5), the source of Staff's numbers. Moreover, there was no indication that the Company's numbers were truncated in the work papers provided to Staff, despite the fact that the very same work papers are provided in the Company's Results of Operations and *do indicate* the figures are in thousands.

TABLE 3: 4.2 - WAGES AND EEMPLOYEE BENFITS ADJUSTMENT_CONF (SIC)

TAB 4.2.3-4.2.5 CONF

[redacted]

TABLE 4: PAC RESULTS OF OPERATIONS - DECEMBER 2021

PacifiCorp
Results of Operations - December 2021
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Labor (12 Months Ended December 2021)

Acct	Account Desc.	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21
5001XX	Reg/Ordinary Time	34,599	33,011	39,286	36,563	34,667	36,155	36,489	35,503
5002XX	Overtime	5,000	7,912	4,792	7,095	4,582	5,690	6,893	6,456
5003XX	Premium Pay	746	784	892	1,062	909	1,210	1,340	1,262
Grand Total		**40,345**	**41,707**	**44,971**	**44,720**	**40,158**	**43,054**	**44,722**	**43,222**

Labor (12 Months Ended December 2021)

Group Code	Labor Group	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21
2	Officer/Exempt	15,739	14,376	18,183	16,801	14,865	15,518	16,719	15,072
3	IBEW 125	3,216	4,122	3,460	3,463	3,437	3,542	3,689	3,563
4	IBEW 659	3,704	5,244	3,713	3,535	3,439	3,808	4,321	4,160

Q. Has Staff made any adjustments to the Union overtime adjustment or Officer wages?

A. Given the challenging labor market, the Company's flat FTE growth and in response to Company's testimony that overtime is a natural consequence of a labor shortage, in this rebuttal testimony, Staff has removed the adjustment to Union overtime.[9] For this rebuttal testimony, Staff has also removed the smaller adjustment to Officer salaries.

Q. Did the Company make any adjustments to its incentive adjustments in its Reply Testimony?

A. Yes, the Company has included its bonuses in the incentive calculation. In its initial filing, bonuses were not included in their downward adjustment whereas in its Reply, the Company reduced its bonus calculation by $3.7 million Total Company, as you can see in the below table which compares initial and Reply Testimony adjustments. The Company has also reduced its AIP

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9 PAC/2000/Cheung/13.

calculation by an additional $1 million, making the full reduction to AIP $3.8 million Total Company as well. While these adjustments appear to be generous and a compromise position between Staff and the Company, the overall effect of the Reply Testimony updates actually increase the incentive and labor subtotal by $976 thousand, due in large part to increases in wages, overtime, and premium pay.

FIGURE 2: COMPANY'S WAGES AND EMPLOYEE BENEFITS ADJUSTMENT INITIAL AND REPLY[10]

[redacted]

The Company revised its adjustment to reflect updates to wage escalations for expected increases for union and nonunion wages while also

[10] See PAC Confidential Workpaper 4.2 – Wages and Eemployee Benfits Adjustment_Conf; 4.2.R, 4.2_R - Wages and Employee Benefits_CONF.xlsx.

incorporating mid-year market wage adjustment.[11] In its entirety, the Company's Reply Testimony is an increase of $680 thousand to its Wage and Employee Benefits Adjustment in Oregon numbers.[12]

In addition, the Company has offered an alternative analysis to calculating its AIP and bonuses, stating that the amounts provided in SDR 92 are "artificially low" and should be based on a percentage of AIP dollars relative to total eligible wages.[13] First, Company did not even include bonuses as part of their incentive adjustment until it was in Staff's Opening Testimony, completely excluding the extra $5.9 million in incentives. Second, Staff argued in its Opening Testimony that the Company's projected Test Year AIP amount was inflated at [redacted] when compared to its four-year average of $24 million.[14] Now, the Company is arguing that AIP should be based on a percentage of Exempt wages which is very convenient given the $18 million increase in Exempt wages from calendar year 2021 to Test Year.

11 PAC/2000/Cheung/17.
12 PAC/2000/Cheung/19.
13 PAC/2000/Cheung/14.
14 See Staff/600/Cohen/13.

FIGURE 3: UE 399 SDR 92 EXEMPT WAGES 2021-TEST YEAR

UE 399						
Test Year 2023	**12Mo Avg FTE**	**Base Wages and Salaries**	**Overtime**	**AIP(1)**	**Bonus (2)**	**Total (3)**
Officers (NEO)	3	$ 1,184,342	$ -	$ -	$ -	$ 1,184,342
Exempt	1,790	$ 207,019,054	$ 1,243,679	$ 16,886,838	$ 5,211,243	$ 230,360,814
Non-Exempt/Non-Union	329	19,908,017	956,469	-	86,801	20,951,287
Union	2,629	237,131,988	95,456,911	-	614,522	333,203,422
Total	4,752	$ 465,243,401	$ 97,657,059	$ 16,886,838	$ 5,912,567	$ 585,699,866
(1) Pro Forma annual incentive payments (AIP) after removal of 100% of (NEO's) and 50% of non-officers per GRC order in UE-374.						
(2) Includes bonus, retention and hiring, safety, and performance awards.						
(3) Based on headcount as of 12-month ended June 2021 average.						
Calendar Year 2021	**12Mo Avg FTE**	**Base Wages and Salaries**	**Overtime**	**AIP (1)**	**Bonus (2)**	**Total (3)**
Officers (NEO)	3	$ 1,208,282	$ -	$ 896,512	$ 40,000	$ 2,144,794
Exempt	1,736	188,369,182	1,256,350	24,094,487	4,336,619	218,056,638
Non-Exempt/Non-Union	316	17,887,763	898,980	-	6,336	18,793,079
Union	2,581	222,540,432	83,036,513	-	134,790	305,711,735
Total	4,636	$ 430,005,659	$ 85,191,843	$ 24,990,999	$ 4,517,745	$ 544,706,246

Third, the Company's 2021 Results of Operation (ROO) shows an unadjusted AIP of $24.6 million and an entirely separate amount of bonuses at $6.6 million. Given these discrepancies, and the fact that the Company is well aware of Staff's use of SDR 92 to determine incentives given its last rate case in 2020, Staff will continue to rely on SDR 92 for a four-year average of AIP and bonuses to determine adjustments until the Company resubmits its ROO and SDR 92 with updated methodologies.

FIGURE 4: PAC RESULTS OF OPERATION 2021

PacifiCorp
Oregon Results of Operations - December 2021
Wage and Employee Benefit Adjustment

Account	Description	Actual 12 Months Ended December 2021	Annualized 12 Months Ended December 2021	Adjustment	Pro Forma 12 Months Ending December 2022	Adjustment
5001XX	Regular Ordinary Time	429,992,195	431,286,046	1,293,851	436,458,343	5,172,297
5002XX	Overtime	72,341,721	72,559,398	217,677	73,429,584	870,185
5003XX	Premium Pay	12,850,121	12,888,787	38,666	13,043,359	154,572
	Subtotal for Escalation	**515,184,037**	**516,734,232**	**1,550,194**	**522,931,285**	**6,197,054**
5005XX	Unused Leave Accrual	3,651,465	3,662,453	10,987	3,706,375	43,923
500600	Temporary/Contract Labor	-	-	-	-	-
500700	Severance Pay	1,125,611	386,224	(739,388)	390,855	4,632
500850	Other Salary/Labor Costs	3,962,191	3,962,191	-	3,962,191	-
50109X	Joint Owner Cutbacks	(1,130,266)	(1,133,667)	(3,401)	(1,147,262)	(13,596)
	Subtotal Bare Labor	**522,793,039**	**523,611,432**	**818,393**	**529,843,445**	**6,232,013**
500410	Annual Incentive Plan	24,579,836	24,579,836	-	16,591,533	(7,988,303)
	Total Incentive	**24,579,836**	**24,579,836**	**-**	**16,591,533**	**(7,988,303)**
500250	Overtime Meals	1,567,989	1,567,989	-	1,567,989	-
50040x	Bonus and Awards	6,655,902	6,655,902	-	6,655,902	-
501325	Physical Exam	60,688	60,688	-	60,688	-
502300	Education Assistance	134,787	134,787	-	134,787	-
580899	Mining Salary/Benefit Credit	(160,743)	(160,743)	-	(160,743)	-
	Total Other Labor	**8,258,623**	**8,258,623**	**-**	**8,258,623**	**-**

Q. Has Staff made any adjustments to the incentives adjustment?

A. Yes. In its Opening Testimony, Staff calculated a four-year average to adjust the Company's AIP amount but did not do the same for the bonus amount, instead adjusting the Test Year amount. To maintain consistency, Staff has adjusted the bonus incentive to reflect half of the four-year average (2018-2021) for both bonuses and AIP. Staff's adjustment is now slightly higher at $1.5 million O&M and $790 thousand rate base (excluding incentives capitalized in plant).[15]

Q. Staff has not changed its adjustment to capitalized incentives, correct?

A. Correct. The Company included over $1 million in officer capitalized incentives since 2010.[16] The Company's 10k for the year 2021 describes executive compensation as "annual discretionary cash incentive award determined on a subjective basis at the Chair and CEO's sole discretion and not based on a specific formula or cap."[17] In addition, executives can be awarded "cash performance awards periodically during the year" again approved solely by the Chair and CEO.[18]

In UE 283, $10 million in past capitalized financial performance-based incentives were removed from the PGE's rate base.[19] In UG 435, $4.5 million in incentives were removed from NWN's revenue requirement "in recognition of all past financial performance-based incentives" despite the fact capitalized

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15 See UE 399 Exhibit 2302 Wage and Salary Model Reply CONF.
16 Staff/2301, PAC Response to Staff DR 313.
17 PacifiCorp 10-k 2021. https://www.brkenergy.com/assets/upload/financial-filing/20211231_PAC%20Form%2010-K.pdf.
18 Ibid.
19 See Order 14-422 at 28.

incentives were also removed in the Company's UG 388 rate case two years prior. Until Companies agree to exclude capitalized incentives on a going-forward basis from their rate case (as Avista, Cascade, NWN and PGE have), there is no hard and fast rule prohibiting Staff from removing all capitalized incentives in the current rate case that had not been permanently excluded previously. These are not one-time expenses, are imprudent, and will continue to be funded by customers unless they are removed from rate base in their entirety. The Company, which argues only those officer incentives capitalized since its last rate case should be included, has offered to remove $11 thousand in capitalized incentives.[20]

[20] PAC/2000/Cheung/77.

Q. What are Staff's total adjustments?

A. After removing the smaller adjustments to Officer salaries and overtime, and including capitalized incentives as well as reversing the Reply Testimony labor increases, Staff's adjustment is $2.2 million O&M and $1.8 million rate base.

Preliminary Adjustment

	Company-Wide				OR- Allocated	
Description/ Account No.	**Company Filing**	**Staff**	**O&M Adjustment**	**Capital Adjustment**	**O&M Adjustment**	**Capital Adjustment**
					-	-
Wages & Salaries	$ 465,243	$ 465,224	$ -	$ -	-	-
FTE Adjustment	$ 465,224	$ 465,224	$ -	$ -	-	-
Incentives	$ 22,799	$ 14,982	$ (5,065)	$ (2,753)	(1,454)	(790)
Overtime	$ 97,657	$ 94,195	$ -	$ -	-	-
Payroll Taxes					**(14)**	
Depreciation O&M Adjustment Associated with Capital Adjustment					**(36)**	
Incentives in Plant						**(1,028)**
Reverse PacifiCorp Reply Testimony Increase					**(680)**	**(5)**
Total OR - Allocated Adjustments					**(2,184)**	**(1,823)**

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 399
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2301

Exhibits in Support
Of Rebuttal Testimony

August 11, 2022

Docket No: UE 399

UE 399 / PacifiCorp
May 6, 2022
OPUC Data Request 313 -1st Supplemental

OPUC Data Request 313

Annual Incentive Plan (AIP). Long Term Incentive Plan (LTIP) - Please provide the dollar and percentage loading amount of Officer and Executive Incentives capitalized in Plant Costs by year for the time period 2010 through 2021. Please explain how the amount of Officer and Executive incentives capitalized in plant costs is consistent with Commission practices with regards to the amount included in rates and Commission orders issued.

1st Supplemental Response to OPUC Data Request 313

Further to the Company's response to OPUC Data Request 313 dated April 21, 2022, the Company provides the following supplemental response to provide the requested information for calendar year 2021:

PacifiCorp continues to object to this data request on the grounds that it is overly broad, unduly burdensome, seeks information that is outside the scope of this proceeding, and is not reasonably calculated to lead to the discovery of admissible evidence. Subject to and without waiving the foregoing objections, PacifiCorp responds as follows:

Please refer to the table below for the amount of Annual Incentive Plan (AIP) awards for PacifiCorp's named executive officers (NEO), capitalized to FERC Account 107 (Construction Work In Progress (CWIP)) for calendar year 2021. The Company cannot specifically state the amount of NEO incentive in CWIP that was placed in service to electric plant in-service (EPIS) for any year, or the amount allocated to Oregon. The amounts below are estimates of the NEO incentives in electric plant allocated to Oregon. The Company is unable to estimate the depreciated value of these amounts and therefore cannot provide the net amount included in rate base allocated to Oregon.

Calendar Year	**PacifiCorp NEO, Capitalized AIP**	**Oregon's Allocated share [1]**
2021	$ 316,452	$ 88,581

1. Oregon's Allocated share is extrapolated using an unadjusted gross electric plant in service percentage calculated as: Oregon's gross EPIS balance divided by Total Company gross EPIS balance. Gross EPIS balances are sourced from the Company's annual results of operations (ROO) filings.

UE 399 / PacifiCorp
April 21, 2022
OPUC Data Request 313

OPUC Data Request 313

Annual Incentive Plan (AIP). Long Term Incentive Plan (LTIP) - Please provide the dollar and percentage loading amount of Officer and Executive Incentives capitalized in Plant Costs by year for the time period 2010 through 2021. Please explain how the amount of Officer and Executive incentives capitalized in plant costs is consistent with Commission practices with regards to the amount included in rates and Commission orders issued.

Response to OPUC Data Request 313

PacifiCorp objects to this data request on the grounds that it is overly broad, unduly burdensome, seeks information that is outside the scope of this proceeding, and is not reasonably calculated to lead to the discovery of admissible evidence. Subject to and without waiving the foregoing objections, PacifiCorp responds as follows:

Please refer to the table below for the amount of Annual Incentive Plan (AIP) awards for PacifiCorp's named executive officers (NEO), capitalized to FERC Account 107 (Construction Work In Progress (CWIP)). The Company cannot specifically state the amount of NEO incentive in CWIP that was placed in service to electric plant in-service (EPIS) for any year, or the amount allocated to Oregon. The amounts below are estimates of the NEO incentives in electric plant allocated to Oregon. The Company is unable to estimate the depreciated value of these amounts and therefore cannot provide the net amount included in rate base allocated to Oregon.

Notes:

Calendar Year	PacifiCorp NEO, Capitalized AIP	Oregon's Allocated share [1]
2010	$ 249,099	$ 69,045
2011	$ 261,666	$ 72,537
2012	$ 286,916	$ 78,405
2013	$ 325,271	$ 86,961
2014	$ 256,971	$ 69,236
2015	$ 256,415	$ 69,430
2016	$ 271,205	$ 75,137
2017	$ 410,100	$ 111,165
2018	$ 295,922	$ 80,898
2019	$ 397,773	$ 109,557
2020	$ 416,671	$ 117,263
2021	Not available [2]	Not available [2]

1. Oregon's Allocated share is extrapolated using an unadjusted gross electric plant in service percentage calculated as: Oregon's gross EPIS balance divided by Total Company gross EPIS balance. Gross EPIS balances are sourced from the Company's annual results of operations (ROO) filings.

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April 21, 2022
OPUC Data Request 313

2. Calendar year 2021 allocation is not yet available for inclusion in the above table until sometime after the Company's 2021 ROO is filed with the Public Utility Commission of Oregon (OPUC) on or about April 30, 2022.

STAFF EXHIBIT 2302

IS CONFIDENTIAL AND FILED IN

ELECTRONIC FORMAT

PROTECTIVE ORDER 22-044

CASE: UE 399
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2400

Rebuttal Testimony

August 11, 2022

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

A. My name is Curtis Dlouhy. I am an economist 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. I provided testimony in Exhibit Staff/700.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the Company's and parties' testimony on the following issues:

- The marginal cost study
- Rate spread
- Residential rate design issues
- Irrigation Distribution Peaks
- Paperless bill credit

Q. Did you prepare any exhibits for this rebuttal testimony?

A. Yes. I prepared two exhibits:

- Exhibit Staff/2401, which contains responses to data request I use in support of my rebuttal testimony.
- Exhibit Staff/2402, which contains other document used in support of my rebuttal testimony.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Marginal Cost Study 3
Issue 2, Rate Spread 9
Issue 3, Residential Rate Design 16
Issue 4. Irrigation Distribution Peaks 40
Issue 5. Paperless Bill Credit 42

ISSUE 1. MARGINAL COST STUDY

Q. Please discuss the parties' and Company's positions on the marginal cost study.

A. In its opening testimony, Alliance of Western Energy Consumers (AWEC) brings up the same concern as Staff, which is that computing the marginal cost of generation by using simple-cycle combustion turbine (SCCT) and combined-cycle combustion turbine (CCCT) power plants is inappropriate because the Company has no intention of using these resources to serve any incremental load.[1] However, AWEC uses a different method than Staff, and instead proposes that the marginal cost of generation's two subcomponents—the marginal cost of energy and the marginal cost of capacity—be calculated by using a single wind facility and a single stand-alone battery, respectively.[2] In practice, AWEC's method results in vastly different marginal cost estimates than Staff's method because Staff's method incorporates a weighted average of renewable resources coming online as well as the storage components of solar plus storage facilities.

The Company opposes moving away from the using SCCT and CCCT plants in the marginal cost of generation calculations, citing that it has been Company practice to use the same avoided cost methodology as is used to estimate the avoided cost for qualifying facilities, and that both proceedings use the same peaker methodology.[3] The Company also argues that it is

1 AWEC/200, Kaufman/4.
2 AWEC/200, Kaufman/1.
3 PAC/2100, Meredith/5.

unclear what would be gained from using Staff's analysis because the results were very similar to the Company's SCCT and CCCT method. The Company argues that Staff's method of ascribing the renewable costs to the cost of capacity is inappropriate and that Staff's technique of taking the weighted average of resources coming online through 2030 is overly complex.[4] In lieu of adopting Staff's or AWEC's methods to integrate renewables into the avoided cost methodology, the Company proposes the use of the Renewable Future Peak Credit methodology that it uses in its Washington proceedings.[5]

Q. How do you respond to the Company's claim that your method of ascribing the capacity contribution of renewable resources to the marginal cost of capacity is incorrect?

A. I disagree and believe that the Company omits a key part of my methodology discussed in testimony. My marginal cost of capacity is not just calculated using the capacity contribution of renewable resources, but also the storage component of any solar plus storage project. In fact, the majority of the marginal cost of capacity estimate in my opening testimony is driven by the storage component of the solar plus storage projects contained in the 2021Integrated Resource Plan (IRP) data. The Company claimed in its reply testimony that the capacity contribution should measure the portion of nameplate capacity that can be relied upon to serve peak load. Absent using a

4 PAC/2100, Meredith/6.
5 PAC/2100, Meredith/7.

storage facility to exploit wholesale arbitrage opportunities, I fail to see what purpose a storage facility has apart from serving peak load.

I also disagree with the Company's claim that the capacity contribution of an intermittent renewable resource does not belong in the marginal cost of capacity calculations. A renewable resource without any storage backup such as wind still probabilistically contributes to addressing peak loads and as such, a portion of its costs should be thought of as addressing incremental capacity needs. However, I do note that disentangling the particular capacity contribution of an intermittent renewable resource without storage attached to it may require more sophistication than what I presented in my opening testimony.

I re-create my marginal cost study using just the storage component of a solar plus storage facility in my marginal cost of generation augmented in the same way as I described in my opening testimony.[6] It should be pointed out that although this does raise the avoided capacity cost, the revenue requirement at marginal cost falls and the final values in the unbundled revenue requirement change very little from the marginal cost study provided in my opening testimony.

Q. How do you respond to the Company's claim that the SCCT and CCCT method should be used because the same method is used to calculate the QF avoided costs?

[6] Staff/700, Dlouhy/10.

A. I strongly disagree with this claim because I believe that there is no reason that these two avoided costs studies should be tied together. The Commission has a variety of proceedings that rely on avoided cost studies for many purposes such as resource pricing, evaluating program cost effectiveness, procurement, and setting retail rates. Many of these proceedings rely on different avoided cost methodologies than the one used in the qualifying facility (QF) avoided cost filings and the marginal cost study.

Given that these other proceedings rely on different methodologies, the claim that the marginal cost study must be tied in particular to the QF avoided cost methodology is short-sighted and inconsistent. Further, PacifiCorp has two avoided costs: one for renewable resources and one for non-renewable resources. For retail pricing, there is one marginal cost concept and that is based on the resource mix, both renewable and non-renewable, that the utility plans to add in the future.

Further, as I stated in my opening testimony and is supported by AWEC in its opening testimony as well, a marginal cost study that is used to quantify the incremental cost of adding generation to the system should rely on resources that will actually be added to the system.[7,8]

Q. Do you agree with AWEC's methodology of using a single wind resource and a single 200 MWh Li-Ion battery from the Company's 2021 IRP data?[9]

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7 Staff/700, Dlouhy/6.
8 AWEC/200, Kaufman/4.
9 AWEC/200, Kaufman/6.

A. No. I think AWEC's method eliminates valuable information from the IRP that is needed when integrating renewable resources. Unlike a SCCT or CCCT, renewable resource costs vary greatly with geographic and climate conditions as well as proximity to existing infrastructure. Further, the Company develops its IRP plan holistically, meaning that no one project sits in a vacuum. Using just a single resource from this entire array of projects of varying sizes at distinct sites that all fit into a larger goal can paint an inaccurate picture of resource costs.

Q. Do you recommend changing your opening testimony use of the weighted average of wind and solar resources coming online from 2023 through 2030?

A. No. For the reasons described above, I find that my method produces a superior estimate of the marginal cost of generation than the single resource options proposed by AWEC.

Q. Have you updated anything from your previously filed marginal cost study?

A. Yes. As noted previously, I take out the capacity contribution of wind from the marginal cost of capacity in my updated marginal cost study.

Q. The Company recommends that the Commission adopt the Renewable Future Peak Credit Method adopted in its most recent Washington rate case.[10] Do you support the use of this method?

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[10] PAC/2100, Meredith/7.

A. No. While I appreciate that the Company proposes an alternative method to bring relevant information about renewable storage and generation into Oregon, the Renewable Future Peak Credit Method appears to be an indirect method that would still rely on carbon-emitting resources that will not be added to the system to derive the total marginal cost of generation. While the Renewable Future Peak Credit Method may prove to be valuable in some proceedings in Oregon, it does not address my concern of using SCCT and CCCT plants to calculate the marginal cost of generation.

ISSUE 2. RATE SPREAD

Q. Please summarize the parties' positions on rate spread.

A. The parties' positions on rate spread in their reply testimony are as follows:

- In its opening testimony, Walmart does not oppose the overall rate spread proposed by the Company but proposes that the first $5 million of reductions to revenue requirement in this case be used to reduce the Rate Mitigation Adjustment (RMA) for Schedules 28 and 30 down to the levels approved in PacifiCorp's previous rate case.[11]
- Klamath Water Users Association (KWUA) and Oregon Farm Bureau Federation (OFBF) advocate that irrigation customers should receive no more than the average rate increase in this rate case, which is consistent with how the Company treats its Washington and California irrigation customers.[12]
- Small Business Utilities Advocates (SBUA) advocates to bring Schedule 23 rate increases down from 9.5 percent to 9.1 percent to match residential customers.[13] SBUA also recommends a "banding" approach that would set the minimum and maximum rate increase that is a function of the average rate increase.[14] Additionally, SBUA takes issue with residential customers receiving a higher base rate increase than

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[11] Walmart/100, Kronauer/13.
[12] KWUA-OFBF/100, Reed/7.
[13] SBUA/100, Steele/14.
[14] SBUA/100, Steele/10.

Schedule 23 customers but a lower net rate increase than Schedule 23 customers.[15]

- Citizens' Utility Board (CUB) opens its testimony by noting the overall rate shock caused by the combined large rate increases caused by this rate case, the Transition Adjustment Mechanism (TAM), and the Power Cost Adjustment Mechanism (PCAM).[16] CUB witness Will Gehrke also proposes a comprehensive rate spread table in its opening testimony.[17] Of note, CUB's rate spread proposal reduces Residential Schedule 4 rate increases from 9.1 percent to 8.34 percent, proposes the same increase for Schedule 23 customers, and proposes no more than a 10.7 percent increase to any customer class.
- In the Company's rebuttal testimony, it recommends that no party receive more than 50 percent over the average increase and that residential customers receive no more than 40 percent over the average rate increase.[18] This is done by crediting Schedule 23 and Schedule 41 customers using the RMA while applying surcharges to Schedule 28, Schedule 30, and lighting customers. The Company objects to Staff's proposals of capping the increase at more than 25 percent of the average increase for any customer class and my proposal to rate spread proposal that modified both base rates and net rates.[19]

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15 SBUA/100, Steele/13.
16 CUB/100, Jenks/3.
17 CUB/200, Gehrke/38.
18 PAC/2100, Meredith/14.
19 PAC/2100, Meredith/12.

Q. How do you respond to Walmart's recommendation that the first $5 million of revenue requirement reduction should be used to bring the lower the Schedule 28 and Schedule 30 RMA adjustments down to their previous levels?

A. I do not agree with Walmart's recommendation. The RMA is set up as an adjustment to net rates that mitigates burden to customer classes that may otherwise experience rate shock. It is set up to be cost neutral when applied to all customer classes, so reducing the RMA adjustment to Schedule 28 and Schedule 30 customers will necessarily shift the rate shock to other customer classes. If there were a compelling reason that these customer classes needed this additional measure to mitigate rate shock, this could be justified. However, Walmart has presented no evidence that it has experienced an added burden that warrants this shift.

Q. How do you respond to KWUA-OFBF's claim that its rate increase should be set at the average rate increase to be consistent with how the Company treats its Washington and California customers?

A. I do not find this to be a compelling reason to keep OFBF's rates at the average increase. Although it is sometimes useful to see what is being done in other states, the Commission is not beholden to the actions in other states when setting rates.

Q. How do you respond to SBUA's recommendation to match the Schedule 23 rate increase to the rate increase given to residential Schedule 4 customers?

A. I do not agree with this recommendation on the basis that Schedule 23 customers are a distinct customer class from the residential customers in Schedule 4. The intent of creating different tariffs and schedules is to group customers with similar circumstances and usage patterns together and set a fair rate for that group. The small businesses that largely make up the Schedule 23 customer class have different energy consumption behaviors than the residential customers of Schedule 4, therefore I believe that tying the rate increases of the two classes together is inappropriate. Although it would not necessarily be inappropriate to see these two customer classes to get an identical or similar rate increase in practice, I find no compelling reason to tie them together in theory.

Q. How do you respond to SBUA's recommendation to establish "bands" that set a minimum and maximum rate change relative to the average rate change?

A. I agree with this approach and note that this is what was proposed by both the Company and Staff in opening testimony, and the Company in its reply testimony. Staff's opening testimony can be interpreted as recommending bands at zero percent and 125 percent, while the Company's reply testimony can be interpreted as having bands at zero percent and 150 percent.[20] I favor this approach as a means to bring rates closer to parity, limit rate shock, and establish a set of principles up front while revenue requirement adjustments are being made throughout the course of the rate case.

[20] PAC/2106, Meredith/1.

Because PacifiCorp is proposing a significant rate increase in this case, I recommend no class of customers receive less than a two percent increase and no customer class receive a rate increase of more than 150 percent of the overall rate increase. However, if the overall rate increase is no more than four percent, then I would be comfortable removing the minimum two percent increase.

Q. How do you respond to SBUA's criticism that residential Schedule 4 customers receive a lower net rate increase than Schedule 23 customers even though the base rate increase for Schedule 4 customers is higher?

A. The reason for this split between net rates and base rates is largely driven by the Company's choice of how to allocate the RMA, with a large portion of benefits going to residential consumers. SBUA claims that the effects of the COVID-19 pandemic hit small business hard and thus further rate mitigation measures should be taken for Schedule 23 customers.[21]

I understand and agree with SBUA's claim that Schedule 23 customers were adversely affected by the economic fallout from the COVID-19 pandemic. Although I object to the idea of linking small business and residential utility customers into a single group, in this case I find their circumstances to be similar in warranting extra protection against rate shock. Therefore, I am supportive of using the RMA to mitigate some of the rate increase to Schedule 23 customers, but not to the extent that those customers necessarily

[21] SBUA/100, Steele/14.

see the same level of rate increase as residential customers for the reasons cited previously.

Q. How do you respond to CUB's proposed rate spread in its reply testimony?

A. I found CUB's proposed rate spread to be very similar to Staff's rate spread in opening testimony and found their recommendation to be generally acceptable. With all the adjustments, rate mitigation measures, and competing interests that influence rate setting, rate spread is better thought of as an art than a science. As such, there may be many rate-spread proposals that adequately balance competing rate setting goals. I find that CUB's proposed rate spread reasonably balances concerns of overall rate shock (looking at rate increases in this docket and other PacifiCorp dockets) and movements towards parity. However, given the fluid nature of costs in a rate case, I would prefer a proposal that more clearly articulates guidelines to follow as the total revenue requirement in this case evolves.

Q. In its reply testimony, the Company objected to your method of adjusting both base rates and net rates in forming your recommendation. How do you respond to this?

A. While I stand by my method of adjusting both base and net rates, I find the specifics of whether net rates or base rates were adjusted to be less important than the overall net rate spread recommendation. The exact numbers contained in my net rate spread proposal could have also been obtained by limiting my adjustments to just the RMA. In that regard, the Company's objection is noted, but my final recommendation of limiting the net rate increase has changed to adopt the PacifiCorp proposals of no more than 150 percent of the average rate increase for any customer class. I do note that this proposal is tempered by also recommending no customer class receive less than a two percent increase.

Q. How do you respond to the Company's proposal to limit rate increases to all customer classes to no more than 150 percent of the average rate increase and capping the residential customer increase to 140 percent?

A. I support these elements of the Company's proposed rate spread. As I stated previously when discussing CUB's proposed rate spread, there may be many candidate rate spreads that accomplish the overall goals of limiting rate shock to vulnerable classes, moving towards parity, and setting a set of guidelines to handle rate spread as the final revenue requirement number becomes known. I find that the Company's proposed rate spread also reasonably accomplishes all these goals. The 140 percent cap on residential Schedule 4 customers limits some rate increase in an unprecedented inflationary time, the credit to Schedule 23 customers does provide some level of assistance that I believe small business customers deserve, and the established 150 percent and 140 percent upper bands provide a convenient rule of thumb that allows for a structured rate spread in this case while still moving towards parity, along with a minimum two percent rate increase.

ISSUE 3. RESIDENTIAL RATE DESIGN

Q. Please summarize your position and recommendation on the Company's residential rate design proposals from your opening testimony.

A. In my opening testimony, I question the Company's choice of a proxy group and classification of fixed assets when discussing its justification for increasing the basic charge. I support the Company's move to flat rates by noting that block-inverted rates are no longer economically justified. In response to the Company's proposal to also impose a 1.9 cent per kwh summer-winter rate differential, I note that a seasonal rate differential is cost-justified based on the costs that appear to be imposed on the system but that the 1.9 cent per kwh proposed by the Company does not have a strong cost justification argument. Because of this, I propose a 1.4 cent per kwh cost differential based on historic sales price of wholesale electricity at various hubs as weighted by the historic sales volumes at those hubs. Finally, I oppose the Company's proposal to flatten the Schedule 98 benefits on equity grounds and instead propose that a 1000 kWh cap is reimposed, or, alternatively, the benefits be distributed on a per-customer basis.[22]

Q. Please summarize the parties' positions on residential rate design in their opening testimonies.

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[22] Staff/700, Dlouhy/22.

A. CUB supports reducing the block and flattening volumetric rates but opposes implementing the seasonal rate differential.[23] Unlike Staff in opening testimony, CUB is open to flattening the Bonneville Power Administration (BPA) Residential Exchange Program (REP) contained in Schedule 98 on the basis that REP-related benefits accrue volumetrically and are best distributed in the same manner.[24] Further, CUB opposes raising the single-family basic charge from $9.50 to $12.00 on the grounds that it makes electricity less affordable for low-usage residential customers. Residential customers have preferences for a low basic charge, and an increased customer charge shifts business risk away from PacifiCorp and onto residential customers.[25]

Q. Please summarize the Company's response to your testimony and parties' testimony on residential rate design in its reply testimony.

A. The Company objects to my argument that transformers have a volumetric interpretation and thus should contain a volumetric component. It also disagrees with my choice to compare the Company's basic charge to only Oregon investor-owned utilities.[26] Further, the Company disagrees that a proper comparison group should only contain other Commission-regulated utilities.[27]

While the Company agrees with my assessment that demand response and time-of-use programs are important components to electric vehicle (EV)

[23] CUB/200, Gehrke/14.
[24] CUB/200, Gehrke/23-24.
[25] CUB/200, Gehrke/25-26.
[26] PAC/2100, Meredith/15-18.
[27] PAC/2100, Meredith/18-19.

adoption, the Company reasserts that inverted block rates pose an obstacle to EV adoption.[28]

The Company also restates the 1.9 cents per kWh seasonal rate differential that it proposed in its opening testimony on the basis that its differential is reasonable and is forward looking as opposed to Staff's differential, which is based on past market operations.[29] Additionally, the Company disagrees with CUB's assertions that seasonal rates arbitrarily benefit some customers while disadvantaging others, as well as the argument that customers are unable to react to the price signals sent by seasonal rates, and that the heterogeneous geographic effects of a seasonal rate design are not well understood.[30] The Company also focuses its testimony on discussing the annual effects of a seasonal rate design instead of just the impacts of raising rates in the summer.

Finally, the Company objects to the idea of disbursing Schedule 98's Residential Exchange Program (REP) benefits on a per-customer basis. Although the Company believes the 1000 kWh proposed by Staff in opening testimony is too restrictive, the Company does believe that some cap is warranted without specifying a cap.[31]

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[28] PAC/2100, Meredith/20.
[29] Id.
[30] PAC/2100, Meredith/23.
[31] PAC/2100, Meredith/21-22.

Q. How do you respond to the Company's reply testimony?

A. First, the Company focuses its response to my criticism of the basic charge regarding line transformers. When mentioning transformers as something with a volumetric interpretation in my opening testimony, I erroneously concluded that the transformers included in the Company's filed workpapers referred to substation transformers, which I believed to have a volumetric interpretation. While I still consider substation transformers have a clear volumetric component, I understand the Company's argument of treating line transformers as a customer cost. However, in responses to data requests, the Company does acknowledge that individual customers may have additional transformers installed if usage requires.[32] Given that the design of the residential customer limits the assumed need for transformers, I find the Company's reasoning is sound.

Second, I continue to support the Company's shift to flat rates. However, I disagree with the Company's assessment that the current inverted block rates are a hindrance to EV adoption.

Third, I still find the Company's 1.9 cents per kWh poorly substantiated and reassert that a 1.4 cents per kWh differential is more appropriate both due to informed past market operations and as a way to ease customers into an entirely new rate design. Although I think my seasonal differential is more appropriate than that proposed by the Company.

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32 Staff/2401, Dlouhy/1.

Finally, after further consideration of the Company's testimony, I propose a 2,000-kWh cap to continue to address Staff's concerns about REP benefits disproportionately benefiting high users while still making rates effectively flat for the vast majority of PAC customers.

Q. Regarding your first point, do you support the Company's treatment of line transformers as a customer cost?

A. Yes. In its reply testimony, the Company notes that upgrading a customer line transformer from 25 kVA to 50 kVA increases costs from $4,113 to $4,466, a negligible change when compared to the overall cost of the transformer.[33] Staff understands and agrees with this point. As stated previously, I erroneously interpreted the transformer cost in the Company's basic charge analysis to be transformers at the substation level.

Q. How do you respond to the Company's criticism of comparing its basic charge to only other investor-owned utilities?

A. I disagree with the Company's claim that it is inappropriate to compare its basic charge to only other Oregon investor-owned utilities. The Company is correct that there is a cost-of-service argument to support a higher basic charge,[34] but the cost of service is not the only component that matters when discussing fair, just and reasonable rates. I still maintain that the fairest comparison rests with other Oregon investor-owned utilities.

[33] PAC/2100, Meredith/16.
[34] PAC/2100, Meredith/19.

Q. Does this change your recommendation on the residential basic charge?

A. No. When making my recommendation in opening testimony, I presented both the cost causation argument and the comparison to other Oregon investor-owned utilities and said that the increase in the basic charge was justified. Although I take back my removal of transformers from the basic charge, my opening testimony and rebuttal testimony still are consistent in presenting a cost causation argument in support of the Company's proposed changes in the basic charge and a case against raising the basic charge when compared to other Commission-regulated peers.

It is also worth noting that shifting costs to the basic charge have adverse equity implications by shifting costs to lower-usage customers, who have a higher propensity to be energy-burdened.[35] I will expand upon the intersection between the Company's residential rate design proposals and equity later in my testimony.

Q. Regarding your second point, why do you disagree with the Company's claim that the inverted block rate is a disincentive to EV adoption?

A. The Company makes the claim that the current block rate structure disincentives EV adoption because of the price signal sent by increased volumetric prices at 1,000 kWh.[36] In moving to a flat rate design, the marginal

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[35] Staff/2402, Dlouhy/146.
[36] PAC/2100, Meredith/19.

cost for electricity for a customer using over 1,000 kWh in a billing cycle will go down as volumetric costs are shifted away from what was formerly the second block.

However, the Company's argument appears to claim that the discontinuous effect of seeing a higher price once a customer passes 1,000 kWh is dissuading residential customers from adopting EVs. This argument hinges on the assumption that EV users typically have usage below 1,000 kWh. Given that EV buyers tend to be wealthier than the average consumer and wealthier customers tend to have higher usage, it is very likely that a residential PacifiCorp customer has already met or exceeded the 1,000-kWh threshold.[37]

Q. Have you done anything to quantify the propensity of wealthier customers to have usage above the 1,000-kWh threshold?

A. Yes. Using the Company's 2019 Residential Email Survey provided in its workpapers, I calculate the average monthly usage of a household in the survey whose income exceeds $100,000 annually. My priors are that a typical EV buyer at this time would have a substantially higher household income, so I view $100,000 to be a conservative estimate.[38] Using the Company's survey, I find that customers with at least this income level consume on average 1,004 kWh per bill. This level appears to only go up when only higher income brackets are chosen. Therefore, it appears likely to me that a typical EV buyer

[37] Staff/2402, Dlouhy/81.
[38] *Id.*

in the Company's market has already met exceeded the 1,000 kWh first block and would not be disincentivized by the discontinuous rate hike in the second block. For this reason, I do not fully believe the Company's argument that the inverted block rates present an obstacle to EV adoption.

Q. Do you continue to still support the Company's proposal to flatten its residential volumetric rates?

A. Yes. Although I question the claim that inverted block rate design is standing in the way of EV adoption, I am supportive of removing the inverted block rates like I was in my opening testimony. A better alternative for EV adoption is time-of-day rates and we should focus on that rate structure. This is substantiated further by the EV Consumer Behavior report I previously cited.[39]

Q. Regarding your third point, why do you continue to believe that your 1.4 cents per kWh differential is more appropriate than the 1.9 cents per kWh differential proposed by the Company?

A. Although I understand the Company's desire to incorporate forward-looking prices into its seasonal rate differential, I continue to disagree with the 1.9 cent per kWh differential proposed in the Company's opening testimony, which is based on the seasonal price differential of wholesale electricity at the Mid-C hub.[40] In my opening testimony, I disagree with this because it fails to capture both how the Company's internal costs change between the seasons and the prices that the Company faces in all the hubs where it transacts.[41] Additionally,

39 Id.
40 PAC/1100, Meredith/26.
41 Staff/700, Dlouhy/31-36.

a smaller differential of 1.4 cents per kWh would help ease the magnitude of the rate design change for customers.

Q. Has Staff changed its position from opening testimony where it supports seasonal rates on a cost causation basis?[42]

A. No. I still believe that seasonal rates are cost-justified systemwide and better align customer rates with cost causation. It promotes parity to have cost causers, those using electricity more intensively in the summer, to pay more reflecting the relatively higher cost to serve. However, I do wonder why the Company is proposing a seasonal rate design for only the residential customer class, as the cost causation argument appears to hold true for all customer classes and the Company removed seasonal rates from the irrigation customer class in 2021. In this regard, I hold the position that seasonal rates should be implemented for all major customer classes.

Staff's recommendation on seasonal rates also includes protections for energy-burdened households. As pointed out in CUB's opening testimony, seasonal rates introduce equity concerns to energy-burdened households.[43] To the extent a seasonal rate design causes more variance in customer's bills, Staff believes that the Company could mitigate this burden in part by implementing an equal-pay plan for energy-burdened customers or tuning other existing energy burden programs. I believe that the Company should be directed by the Commission to increase its outreach and communication of its

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[42] Staff/700, Dlouhy/31-33.
[43] CUB/200, Gehrke/17.

equal-pay plan so that energy-burdened customers are aware of how they can equalize their bills over the year.

Q. What equity issues are presented by CUB in its opening testimony on residential seasonal rates?

A. CUB presents two main arguments in opposition to the Company's proposed seasonal rate design. The first argument is that a system-wide seasonal rate design in Oregon does not send a fair price signal to all of the Company's Oregon customers due to the many different climate regions in the Company's Oregon service territory.[44] The Company counters this by presenting a table demonstrating that the imposition of seasonal rates affects all of the Company's climate zones relatively similarly.[45]

Their second argument is that a seasonal rate imposes a "summer penalty" on a large group of Oregon customers who are unable to react to the seasonal rate signal sent by a higher summer price through being beholden to a landlord that won't update equipment or weatherize a rental unit.[46] The Company responds to this overall equity concern by citing Staff's investigation into implementing House Bill (HB) 2475, existing low-income programs, and a table that shows that the annual effect of a seasonal rate design results in fewer energy-burdened customers according to its 2019 Residential Email Survey.[47]

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44 CUB/200, Gehrke/18.
45 PAC/2100, Meredith/26.
46 CUB/200, Gehrke/21.
47 PAC/2100, Meredith/28-29.

Q. How do you respond to CUB's first claim and the Company's response to it?

A. Much like the Company, I do not agree with CUB's claim that the price signal is unfair due to the various climate regions in Oregon. The intent of the seasonal rate is to both to support cost-based rates as well as potentially balance the system load, so sending a price seasonal signal system-wide should be the goal even if it does affect various geographies differently.[48] A kW saved on the southern Oregon coast has the same system benefit as a kW saved in eastern Oregon during a high demand period. Even though I disagree with CUB's assertion that seasonal rate design unfairly burdens customers of different geographies, this does not discount CUB's argument regarding a "summer penalty" imposed by a seasonal rate design.

An argument could be made that covariates between regions lead to an unequal energy burden imposed on customers from different geographies. However, the Company's Table 2 presents the dispersion of bill impacts across its geographic regions according to the results of its 2019 Residential Email Survey.[49] I further investigated this dispersion and found that when broken down by season, the bill impacts are still relatively balanced.

Q. How do you respond to CUB's second claim and the Company's response to it?

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48 Even if customers do not change usage, seasonal rates still exemplify cost causation principles since customers who use more electricity relatively in the summer pay more.

49 PAC/2100, Meredith/26.

A. I agree with CUB's claim that a seasonal rate design may disproportionately harm energy-burdened customers but believe that this risk can in theory be partially mitigated by better Company outreach, a comprehensive Low-Income Needs Assessment, and a wider adoption of the Equal Payment option. This does not entirely ameliorate all equity concerns, so I recommend that the Commission direct the Company to work with Staff and stakeholders to better understand the equity implications of seasonal rates and the broader equity concerns.

Q. Can you describe how a seasonal rate design would affect a customer's bill in the summer and winter?

A. Yes. In Table 1, I present the expected changes to summer and winter bills for a PacifiCorp residential customer using the same 2019 Residential Email Survey that the Company uses for the bulk of its equity analysis in its reply testimony. Much like the tables presented by the Company in its reply testimony, Table 1 incorporates the Company's proposed changes to its revenue requirement as well as its other rate design proposals.

Table 1: Seasonal Residential Bill Difference

	Average Bill (Present)	Average Bill (Proposed)	Change	% Change
Summer	$82.70	$107.92	$25.21	30.5%
Winter	$105.31	$114.98	$9.68	9.2%

As you can see, the Company's proposed change causes approximately a $15 larger increase per bill in the summer than in the winter and a very large 30.5 percent increase to a residential customer's summer bill.

Q. Can you explain how the Company's proposed seasonal rate design could impact energy-burdened residential customers?

A. Yes. In the Company's reply testimony on residential rate design, it presents a table that breaks down the effects of its various proposals on the quantity of energy-burdened customers in its 2019 Residential Email Survey.[50] The Company defines energy-burdened customers as those that spend greater than six percent of its household income on energy. This is a common threshold, but some states use thresholds as low as three percent to classify energy-burdened customers.[51]

I recreate this table twice, once for each of the two seasons that PacifiCorp defines for its seasonal rate differential. Table 2 contains the winter version of this table. Because of the limitations of the dataset I have previously pointed out, I find it to be more insightful to interpret the percentage changes rather than the raw customer counts.

As you can see from column 4, within the customers contained in the data the combined effect of the proposals does appear to lower approximately 11.2 percent of the winter energy-burdened customers in the 2019 Residential Email Survey below the six percent threshold for electricity. However, it is worth pointing out that this number does not account for the nuance of which other heating sources these customers actually use. It is very possible that these customers would not see any winter relief because they are not heating

[50] PAC/2100, Meredith/29.
[51] Staff/2402, Dlouhy/149.

with electricity but with natural gas or wood. It is also possible that an energy burdened customer with gas heat could be better off if the Energy Trust of Oregon (ETO) finds a path forward to encourage beneficial electrification with a subsidy for electric heat pumps.

Table 2: Winter Energy-Burdened Customers Under Proposed Rate Designs

	Pricing Scenario					
	1) Equal Increase to Energy Charges	**2) Increase Single Family Basic Charge to $12**	**3) Flatten Base Energy Charges**	**4) Seasonal Flat Base Energy Charges**	**5) Flatten BPA Credit**	**Total Rate Design Impact**
Net First Block kWh, 0-1,000 (¢/kWh)	10.532	10.301	10.646	(1.142)		
Net Second Block kWh, > 1,000 (¢/kWh)	12.844	12.613	11.580	(0.208)		
Net Summer kWh (¢/kWh)				13.178	12.264	
Net Winter kWh (¢/kWh)				11.249	10.335	
Net Single-Family Basic Charge ($/month)	9.64	12.18	12.18	12.18	12.18	
Net Multi-Family Basic Charge ($/month)	8.12	8.12	8.12	8.12	8.12	
Winter Energy Burdened Customers in Survey	1,306	1,283	1,246	1,106	1,080	
Change with Each Scenario		-1.8%	-2.9%	-11.2%	-2.4%	**-17.3%**

Table 3 presents the summer energy burden under the Company's proposed residential rate design proposals.

Table 3: Summer Energy Burdened Customers Under Proposed Rate Designs

	Pricing Scenario					
	1) Equal Increase to Energy Charges	**2) Increase Single Family Basic Charge to $12**	**3) Flatten Base Energy Charges**	**4) Seasonal Flat Base Energy Charges**	**5) Flatten BPA Credit**	**Total Rate Design Impact**
Net First Block kWh, 0-1,000 (¢/kWh)	10.532	10.301	10.646	(1.142)		
Net Second Block kWh, > 1,000 (¢/kWh)	12.844	12.613	11.580	(0.208)		
Net Summer kWh (¢/kWh)				13.178	12.264	
Net Winter kWh (¢/kWh)				11.249	10.335	
Net Single-Family Basic Charge ($/month)	9.64	12.18	12.18	12.18	12.18	
Net Multi-Family Basic Charge ($/month)	8.12	8.12	8.12	8.12	8.12	
Summer Energy Burdened Customers in Survey	512	515	518	672	665	
Change with Each Scenario		0.6%	0.6%	29.7%	-1.0%	**29.9%**

As can be seen by column four, the Company's proposed seasonal rate design increases the quantity of customers in the dataset paying more than six percent of their income to summer energy costs by a large increase of 29.7 percent. As I have previously pointed out, this is an exceptional burden to put on customers, absent some remedy, in a season where there is mounting evidence that energy burden can lead to adverse outcomes.[52]

Q. Do current programs exist to address the seasonal differences in energy burden?

A. Yes. As the Company pointed out in its reply testimony, the Company's Low-Income Discount (LID) and Low-Income Household Energy Assistance Program (LIHEAP) do lessen the burden to some extent. The numbers presented in Tables 2 and 3 and the Company's equivalent table were calculated assuming that customers receive benefits from these programs. Further, the Company offers an Equal Payment billing option that would spread the burden imposed by a seasonal rate design across the entire year.[53]

Additionally, The Company's Low-Income Discount, which was suspended for further investigation by Commission Order No. 22-290, would provide a refund to low-income customers that is based on the percentage of their total electric bill. The Equal Payment option allows a residential customer to essentially pay each bill over the course of the next 12 months, which mitigates the impact of a single exceptionally high bill. An equivalent equal

[52] Staff/2402, Dlouhy/13.
[53] See the details of PacifiCorp's Equal Payment billing option here.

payment plan exists to bring a customer's arrearage balance down to zero over a longer timeframe.

In addition to the LID, LIHEAP, and Equal Pay options, OAR 860-021-0407(2) requires electric utilities to put into effect a moratorium on the disconnection of residential service for nonpayment on any day a local Heat Advisory is issued by the applicable weather reporting service. There is currently a rulemaking in Docket No. AR 653, and the draft rules in that docket provide additional scenarios and protections for disconnecting customers due to nonpayment during a variety of extreme air quality and weather events.

Q. Does Staff have additional ways that this burden on customers could be ameliorated?

A. Yes. First, the Company could conduct a more robust Low-Income Needs Assessment (LINA) to better understand the impact that a seasonal rate can have on its energy-burdened customers and the demographics of its Oregon service territory. Second, the Company could conduct outreach with its customers to describe the bill impacts and make customers aware of options to reduce energy burden in the summer, such as installing a high-efficiency heat pump or enrolling in the Company's existing programs meant to address equity. Finally, the Company could create an equity group meant to analyze the equity implications of a seasonal rate design or fold this responsibility into an existing internal group. These could be made prior to implementation or concurrently.

Q. Why is the Company's 2019 Residential Email Survey not an adequate substitute for a LINA?

A. Although the 2019 Residential Email Survey does provide valuable data on a subset of approximately 25,000 PacifiCorp customers in Oregon that has a variety of applications, it is unclear how well it extrapolates to PacifiCorp's full Oregon service territory and low-income customers in particular given that responding was voluntary and hence not a random sample. Given that low-income customers tend to be harder to reach, a full LINA would provide a much more comprehensive understanding of low-income demographics and issues than cannot be surmised from the 2019 Residential Email Survey.

Q. Given the protections that you have described, does Staff believe that low-income customers are not going to be affected in a negative way by seasonal rate?

A. No. In fact, all residential customers will be affected by the change to seasonal rates. Some may benefit and some may be harmed, but energy burdened customers are less able to adapt or cope with the change in bills. Seasonal rates are a new rate design for residential customers, and we do not have information about how this will affect low-income customers in practice. Further, a customer is still facing a higher seasonal price signal in the summer than in the winter. If the customer is responding to these prices as the Company is incentivizing customers to do so, then the customer may still reduce summer electricity usage and thereby place themselves into dangerous situations during a heatwave or other exceptional summer weather event.

However, Staff believes that the protections described above, and contained in Staff's recommendation, could ameliorate the equity concerns raised by CUB and explained in this testimony.

Q. Does Staff have a recommendation for how the Company can engage in community outreach to address equity concerns for its customers in its seasonal rate design?

A. Although a contested rate case provides the opportunity for many parties to weigh in and provide testimony on a variety of rate-making issues, the average citizen does not have the time, resources, or experience to engage in this process or even be appraised of every potential change. The broad stakeholder groups that represent an entire customer class may not be able to dig into the environmental justice or equity issues to the detail that they deserve.

Staff recommends that the Commission direct the Company to commission a LINA in Oregon. Other major utilities such as Northwest Natural, Cascade Natural Gas, and Avista have done so. Additionally, the Company should discuss the effects of a seasonal rate design with its internal groups to weigh community and equity considerations or any external community-based organizations.

Q. Has the Company ever implemented seasonal rates in Oregon?

A. Schedule 210 allows customers to enroll in a time-of-use program that has seasonally differentiated peak pricing. According to the Company's response to Staff Data Request 594, the Company also had seasonal rates for agricultural customers prior to 2021 but no longer does.[54]

Q. What is your overall recommendation on the Company's proposed seasonal rate design?

A. I continue to support PacifiCorp's proposal to implement seasonal rates for Residential Customers with a 1.4 cents per kWh differential. However, Staff does have two substantive concerns that I discussed in my testimony. First, Staff is still not certain why the Company is only proposing a change to a seasonal rate design for residential customers if those rates are cost-justified. Second, Staff agrees with CUB that there are significant concerns regarding the impact of seasonal rates to those customers who are energy burdened not enrolled in the outlined bill assistance programs that have not been adequately addressed by the Company.

As discussed previously, there are some existing or soon-to-be-implemented measures meant to address energy burden and its seasonal effects, such as LID, LIHEAP, and the Equal Payment option. However, there are still unanswered equity implication questions that could be solved by an internal equity committee, stakeholder and Staff engagement, and the completion of a LINA. The solutions above could help answer outstanding questions about low-income residents' seasonal price elasticity, low-income residents' demographics, and the burden that would truly be placed on these residents by a seasonal rate. Therefore, Staff recommends that the

[54] Staff/2401, Dlouhy/4.

Commission approve a residential seasonal rate differential of 1.4 cents per kwh at the conclusion of this general rate case, but also direct the Company to immediately begin the analysis, stakeholder engagement, and customer outreach discussed in my first recommendation as well as either make the equal-pay-plan the default option for energy burdened customers or require the customers be well informed of that rate option. This recommendation would also require regular reporting to the Commission on the progress of its LINA and customer outreach.

In the alternative, if the Commission finds that it is preferable to delay the implementation of the seasonal rate design until the Company has engaged in further analysis and outreach, the Commission could delay implementing a seasonal rate differential until the Company's next rate case. This lag would allow the Company to complete a LINA, conduct a thorough analysis of the equity impact of a seasonal rate design with the LINA, engage in discussions with Staff and stakeholders on their equity analysis, and engage in customer outreach with customers to communicate the implications of a seasonal rate design and the available measures to mitigate energy burden. The Commission could direct the Company to file a report on its findings and how its seasonal rate design for residential customers accommodates for the equity concerns identified in this testimony and CUB's testimony. Once the Commission determines that the Company has adequately done the above actions, the Company would then know it has met the requirements identified in this docket and presumably would file for a seasonal rate differential in its next general rate case.

Regardless of whether the Commission chooses to adopt either of these two recommendations, I further recommend that the Company explore implementing seasonal rates beyond the residential class of customers.

Q. Please discuss the pros and cons of your primary recommended course of action that immediately implements residential seasonal rates and requires additional reporting by the Company.

A. The main argument in favor of immediately implementing a residential seasonal rate design is that the cost-causation is strong, improves cost-causation parity among all residential customers, and the Commission has a long history of relying on cost causation when recommending rate design changes. As briefly discussed earlier and brought up by the Company in its testimony, a seasonal rate differential could incentivize beneficial electrification of heating systems and the adoption of high-efficiency heat pumps for summer cooling. Further, the equal pay plan option addresses one of the key concerns of energy burdened customers, namely having difficulty in managing larger variances in their electricity bills.

The main downside of approving a seasonal rate design at the conclusion of this rate case is that the equity implications for lower-income customers are not well known and some of the safeguards for energy-burdened customers are not well developed. PacifiCorp's LID program was suspended for investigation and has not yet been implemented, so the LID eligibility and size of the benefits for energy burdened customers neither known nor implemented as of the filing of this testimony. Further, implementing a seasonal rate with outstanding equity questions and energy burden programs still in their infancy without proper stakeholder engagement runs the risk of eroding community trust that the Commission has long tried to build and maintain.

Q. Please discuss the pros and cons of your alternate recommended course of action that delays the implementation of residential seasonal rates.

A. By establishing some key reporting requirements in order to consider the impacts of seasonal rates more fully for residential energy-burdened customers, the Company is incentivized to complete a LINA, which has uses other than just evaluating the impacts of seasonal rates. Stakeholders and customers are also given a better chance to fully understand the implications of a residential seasonal rate design. Additionally, this level of communication leading up to the eventual implementation fits well into the Commission's ongoing community engagement on equity issues and could help build trust between these groups going forward.

Conversely, waiting until all my recommended conditions prior to implementation are met runs the risk of a delaying an efficient rate design that is well supported on a cost-causation basis and incentivizes beneficial electrification.

Q. Moving on to your next topic, please describe why you propose a 2,000-kWh cap on volumetric Schedule 98 benefits.

A. After reviewing the testimony of CUB and the Company, it is clear that there is appetite to distribute the benefits of the REP on a volumetric basis.[55,56] Additionally, the Company indicated that it is open to some cap on REP benefits in its reply testimony.[57] Staff finds that a 2,000-kWh cap balances Staff concerns of distributing a disproportionate amount of benefits the large users expressed in opening testimony while still keeping rates effectively flat for most customers.

Q. Why do you believe that a 2,000-kWh cap balances these concerns?

A. In my opening testimony, I cite exceptionally large users who consume more than 10,000 kWh on a single bill as reaping an inordinate benefit from the REP under a fully flat rate. The Company replied and noted that it thought Staff was focusing too much on outliers.[58] While I used the example of a 10,000-kWh bill as an example, my concern is still shared for a more moderate extreme user, such as a customer using 3,000 kWh or more on a single bill. As I have previously pointed out in this testimony series, higher-income households tend to correlate with higher-usage households so having some sort of cap should have non-negative equity implications at the very least.

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[55] PAC/2100, Meredith/21.
[56] CUB/200, Gehrke/23.
[57] PAC/2100, Meredith/22.
[58] PAC/2100, Meredith/21.

Raising the cap above 1,000 kWh as I recommend in my opening testimony allows the bills the remain effectively flat for the vast majority of PacifiCorp's Oregon customers while still limiting the payments to a category of users that tend to be higher income.

Q. How many Oregon bills would receive effectively flat rates with a 2,000-kWh cap on the Schedule 98 benefits?

A. As can be seen in Table 6 of my opening testimony, approximately 93 percent of Oregon PacifiCorp residential bills are under 2,000 kWh and thus would be effectively flat.[59] Under the formerly proposed 1,000-kWh cap, only 66 percent of bills would have been effectively flat. I view this as an acceptable solution to limiting benefits to the highest-using residential customers while still distributing the benefits volumetrically. I also believe that this solution is effective in accomplishing the Company's overall residential rate design goal of flattening its rates by making most customers face a flat rate.

[59] Staff/700, Dlouhy/41.

ISSUE 4. IRRIGATION DISTRIBUTION PEAKS

Q. Please describe the issue surrounding the irrigation distribution peaks brought up by KWUA/OFBF in its opening testimony.

A. KWUA/OFBF contended in its opening testimony that the use of the 12-month weighted average distribution peak loads used to forecast demand-related distribution costs among its customer classes was improper due to the monumental heat dome Oregon experienced in June 2020.[60] To support this, KWUA-OFBF's witness Lloyd Reed notes that between the 2021 and the 2023 marginal cost studies, the highest distribution peaks only increase by 7.7 percent for Schedule 41 customers, but the weighted average value that is used allocate demand-related distribution costs increased by 88.1 percent for Schedule 41 customers.[61] Mr. Reed notes that this increase abnormal increase is only felt by the Schedule 41 customers.

Q. How did the Company respond to this in its reply testimony?

A. The Company agreed that this change was abnormal and proposed to calculate the weighted average value using a three-year average instead of a 12-month average to smooth out the effects of the heat dome. Doing so reduces the 88.1 percent increase for Schedule 41 customers down to approximately 26 percent.

Q. Do you agree with the Mr. Reed's argument and the Company's proposed change?

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60 KWUA-OFBF/100, Reed/21.
61 KWUA-OFBF/100, Reed/22.
62 PAC/2100, Meredith/2.

A. Yes. I agree that the June 2021 heat dome had distortionary effects on the distribution loads that are not necessarily indicative of costs if viewed on their own. While the June 2021 heat dome is an occurrence that may become more common due to climate change, it is still a probabilistic event that should not be viewed in isolation. With this in mind, I support substituting the 12-month average with a three-year average as the Company did in its reply testimony. I believe that this can capture valuable information provided by the heat dome without taking an unrepresentative sample. After examining the Company's workpapers, it appears that these changes were applied to all customer classes and properly integrated.

ISSUE 5. PAPERLESS BILL CREDIT

Q. Please describe the paperless bill credit.

A. The paperless bill credit is a reduction to revenue associated with the Company's option for customers to waive receiving a paper copy of their bill. This was approved in UE 374.[62] Due to a change in how the paperless bill credit was implemented, the Company neglected to include it in its opening testimony. In its reply testimony, the Company estimates that offering the paperless bill credit reduces its annual revenues by $2.1 million.[63]

Q. What have you done to verify the accuracy of the Company's $2.1 million estimate?

A. To verify the Company's $2.1 million estimated reduced revenues due to the paperless bill credit, I issued a data request asking the Company to provide the quantity and number of current customers enrolled in the paperless bill credit, and a breakdown of the cost of sending a paper bill to customers. I compared these values to the estimates provided in the Company's filed workpapers and the publicly available information on the paperless bill refund.

Q. How many customers are currently enrolled in the paperless bill program and what is the total estimated cost of the program?

A. According to PacifiCorp's response to Staff DR No. 574, there are 255,961 customers enrolled in the paperless bill program. This comprises 42.6 percent of PacifiCorp customers in Oregon.

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62 PAC/2100, Meredith/2.
63 PAC/2100, Meredith/3.

Q. How does this current level of enrollment translate into an annual level of reduced revenue?

A. The paperless bill program provides customers a credit of 50 cents per bill, meaning that without any growth in enrollment, the Company would pay each of the 255,961 enrolled customers $6 per year. This equates to an annual reduced revenue of $1.535 million, which is about $500 thousand less than the Company requested in this rate case.[64]

Q. How many customers would need to enroll to match the $2.072 million in reduced revenues that the Company proposes in its reply testimony?

A. A reduction in revenue of $2.072 million is equivalent to approximately 345,000 customers enrolling in the paperless bill program, which is slightly over half of all PacifiCorp Oregon customers across all customer classes.

Q. Do you believe that the Company's projection of 345,000 customers enrolling in the paperless bill program by 2023 is accurate?

A. Yes, for two reasons. First, the paperless bill refund only went into effect after the conclusion of UE 374, meaning that it is a fairly new credit. As of now, the Company has only enrolled 42.6 percent of customers. Given recent trends of people relying less on paper bills and the newness of the program, I find it to be reasonable to expect a large swath of customers to enroll in the program given the incentives available.

---

64 Staff/2401, Dlouhy/2.

Second, the Company indicates that although receiving a paperless bill is not the default option, any customer who has provided their email address but is not yet enrolled in the program will be automatically enrolled in the paperless bill program beginning in September 2022.[65] Between customers' expected preference towards paperless bills and the change to automatically enroll customers in September 2022, I find the Company's expected reduction to revenues of $2.072 million to be reasonable.

Q. Does this conclude your testimony?

A. Yes.

---

65 Staff/2401, Dlouhy/3.

CASE: UE 399
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2401

Responses to Staff Data Requests.

August 11, 2022

OPUC Data Request 541

Please discuss how the Company distinguishes the end use and assesses billing of electricity for a customer that engages in commercial or agricultural activity from their residential address. For example, suppose that a residential customer starts to produce an agricultural product on their land that involves increased energy use or runs an energy-intensive at-home business.

Response to OPUC Data Request 541

The Company evaluates the residential status of an existing customer when an existing service is or will be overloaded and creates a need or request to increase the capacity of the service. This can come as a request before the usage is increased or be after the fact when energy usage has increased resulting in an overheated and damaged meter base, service conductor or transformer with reported damages or an outage. In either case, using the new load information from the applicant or measuring the actual kilowatt-hour (kWh) usage of the customer before the outage, the last paragraph of PacifiCorp's Oregon Rule 2 (General Rules and Regulations, Types of Service) sections "Q. Residential Service" and "R. Residential Service (continued)", is applied. This paragraph stipulates if all the load is served from one meter, the customer classification is based on the majority of use. The practical application is to look at the historic load before the increase as the residential load baseline, and the increase as the non-residential load. If the non-residential usage is greater than the residential usage, the customer is placed on a general service schedule.

PacifiCorp's Oregon Rule 2 (General Rules and Regulations, Types of Service) is publicly available and can be accessed by utilizing the following website link:

02_Types_of_Service.pdf (pacificpower.net)

OPUC Data Request 573

Paperless Bill Credit - Please confirm whether or not receiving paperless bills is currently the default option for customers. If paperless bills are something that customers must current opt into, please discuss whether the Company is considering whether to make paperless bills the default option.

Response to OPUC Data Request 573

Receiving paperless bills is not currently the default option for customers. When an applicant requests service, the customer service representative will ask the applicant if they would like to provide an e-mail address and enroll in paperless billing. The applicant has the option to choose paperless billing or decline. Existing customers who have provided email addresses and have not requested paper bills will be auto-enrolled in September 2022 to paperless.

OPUC Data Request 574

Paperless Bill Credit - Please provide the following information:

(a) The total number of customers enrolled in the paperless bill credit.

(b) The percentage of customers enrolled in the paperless bill credit.

(c) A breakdown of the cost to the Company of sending a bill through the mail to a customer.

Response to OPUC Data Request 574

(a) The number of Oregon customers enrolled in paperless billing as of June 30, 2022 was 255,961.

(b) The percentage of Oregon customers enrolled in paperless billing as of June 30, 2022 was 42.6 percent.

(c) Please refer to the table below which provides the average cost of a one-sheet paper bill calculated as follows:

Paper	$0.0107
Envelope	$0.0382
Printing and Mailing	$0.0562
Postage	$0.3910
Total Cost	**$0.4961**

OPUC Data Request 594

Seasonal Rate Design - Please indicate whether the Company has ever implemented seasonal rate differentials for any Oregon class of customer rate schedule. If so, please provide copies of any current or past tariff sheets where the Company has implemented a seasonal rate differential for any Oregon customer class.

Response to OPUC Data Request 594

The Company objects to this request on the basis that it is overly broad and unduly burdensome. Notwithstanding this objection, the Company responds as follows:

The Company examined its tariffs for the past 20 years and found the following examples of seasonal rate differentials in its tariffs:

- Current Schedule 210 (Portfolio Time-of-Use Supply Service) has on-peak energy adders that are different by season.
- Prior to 2021, Schedule 200 (Base Supply Service) rates for Schedule 41 (Agricultural Pumping Service) customers were differentiated by summer and winter season.

Please refer to Attachment OPUC 594 which provides copies of the above referenced tariffs.

CASE: UE 399
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2402

Documents used in Support of Testimony

August 11, 2022

SEPTEMBER 2020

How High Are Household Energy Burdens?

An Assessment of National and Metropolitan Energy Burden across the United States

Ariel Drehobl, Lauren Ross, and Roxana Ayala

aceee.org

ACEEE
American Council for an Energy-Efficient Economy

ABOUT THE AUTHORS

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Executive Summary

KEY TAKEAWAYS

- New research based on data from 2017 finds that high energy burdens remain a persistent national challenge. Of all U.S. households, 25% (30.6 million) face a high energy burden (i.e., pay more than 6% of income on energy bills) and 13% (15.9 million) of U.S. households face a severe energy burden (i.e., pay more than 10% of income on energy).[1]
- Nationally, 67% (25.8 million) of low-income households (≤ 200% of the federal poverty level [FPL]) face a high energy burden and 60% (15.4 million) of low-income households with a high energy burden face a severe energy burden.
- The East South Central Region (i.e., Alabama, Kentucky, Mississippi, and Tennessee) has the highest percentage of households with high energy burdens (38%) as compared to other regions.
- Black, Hispanic, Native American, and older adult households, as well as families residing in low-income multifamily housing, manufactured housing, and older buildings experience disproportionally high energy burdens nationally, regionally, and in metro areas.
- Weatherization can reduce low-income household energy burdens by about 25%, making it an effective strategy to reduce high energy burdens for households with high energy use while also benefiting the environment.
- Leading cities and states have begun to incorporate energy burden goals into strategies and plans and to create local policies and programs to achieve more equitable energy outcomes in their communities. They are pursuing these goals through increased investment in energy efficiency, weatherization, and renewable energy.

1 Researchers estimate that housing costs should be no more than 30% of household income, and household energy costs should be no more than 20% of housing costs. This means that affordable household energy costs should be no more than 6% of total household income. For decades, researchers have used the thresholds of 6% as a high burden and 10% as a severe burden (APPRISE 2005). Note that high and severe energy burdens are not mutually exclusive. All severe energy burdens (> 10%) also fall into the high burden category (> 6%).

This report provides an updated snapshot of U.S. energy burdens (i.e., the percentage of household income spent on home energy bills) nationally, regionally, and in 25 select metro areas in the United States.[1,2] Both high and severe energy burdens are caused by physical, economic, social, and behavioral factors, and they impact physical and mental health, education, nutrition, job performance, and community development. Energy efficiency and weatherization can help address energy insecurity (i.e., the inability to adequately meet basic household heating, cooling, and energy needs over time) by improving building energy efficiency, reducing energy bills, and improving indoor air quality and comfort (Hernández 2016).

We recognize that the economic recession brought on by the global COVID-19 pandemic has greatly increased U.S. energy insecurity and also interrupted weatherization and energy efficiency programs nationally. While this report measures energy burdens using 2017 data from the American Housing Survey (AHS), we anticipate the recession will lead to a further increase in energy insecurity and higher energy burdens in 2020 and beyond.

Methods

This study calculates energy burdens using the AHS, which includes a national and regional dataset as well as a dataset of 25 metropolitan statistical areas.[4] We calculate energy burdens across all households and in a variety of subgroups to identify those that spend disproportionally more of their income on energy bills than otherwise similar groups, analyzing across income, housing type, tenure status, race, ethnicity, and age of occupant and structure. We also calculate the percentage of households nationally, regionally, and in each select metro area that have high energy burdens (i.e., spend more than 6% of income on home energy bills) and severe energy burdens (i.e., spend more than 10% of income on home energy bills). We do not include households who do not directly pay for their energy bills.

Energy Burden Findings

NATIONAL ENERGY BURDENS

U.S. households spend an average of 3.1% of income on home energy bills. Figure ES1 presents our national energy burden findings by subgroup. We acknowledge that many highly burdened groups are intersectional, meaning that they face compounding, intersecting causes of inequality and injustice, with energy burden representing one facet of inequity. The following are key national findings:

- Low-income households spend three times more of their income on energy costs compared to the median spending of non-low-income households (8.1% versus 2.3%).
- Low-income multifamily households spend 2.3 times more of their income on energy costs compared to the median spending of multifamily households (5.6% versus 2.4%).
- The median energy burden for Black households is 43% higher than for non-Hispanic white households (4.2% versus 2.9%), and the median energy burden for Hispanic households is 20% higher than that for non-Hispanic white households (3.5% versus 2.9%).
- The median renter energy burden is 13% higher than that of the median owner (3.4% versus 3.0%).
- More than 25% (30.6 million) of U.S. households experience a high energy burden, and about 50% (15.9 million) of households with a high energy burden face a severe energy burden.[5]
- Of low-income households (≤ 200% FPL), 67% (25.8 million) experience a high energy burden, and 60% (15.4 million) of those households with a high energy burden face a severe energy burden.
- Low-income households, Black, Hispanic, Native American, renters, and older adult households all have disproportionately higher energy burdens than the national median household.

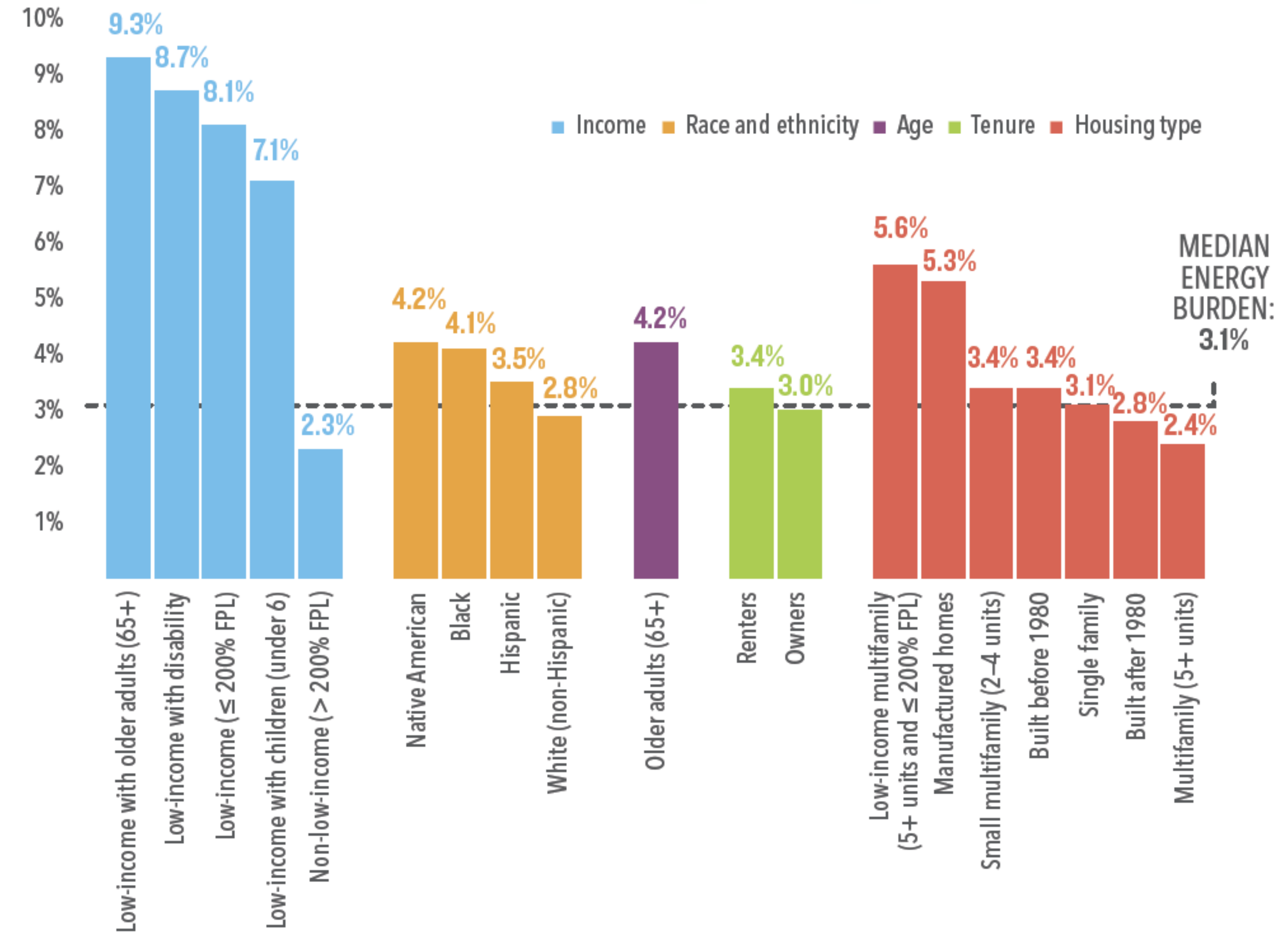
[2] This study focuses on home energy burden and includes electricity and heating fuels. Note that the study does not include transportation, water, or telecommunication cost burdens in its energy burden calculations.

[3] This report provides an update to ACEEE's previous energy burden research. Drehobl and Ross (2016) analyzed 2011 and 2013 American Housing Survey (AHS) data, and Ross, Drehobl, and Stickles (2018) analyzed 2015 AHS data. This report analyzes 2017 AHS data, the most recent data available as of publication.

[4] We include the 25 metropolitan statistical areas (MSAs) sampled for the 2017 AHS: Atlanta, Baltimore, Birmingham, Boston, Chicago, Dallas, Detroit, Houston, Las Vegas, Los Angeles, Miami, Minneapolis, New York City, Oklahoma City, Philadelphia, Phoenix, Richmond, Riverside, Rochester, San Antonio, San Francisco, San Jose, Seattle, Tampa, and Washington, DC.

[5] Note that high and severe energy burdens are not mutually exclusive. All severe energy burdens (> 10%) also fall into the high burden category (> 6%).

FIGURE ES1. National energy burdens across subgroups (i.e., income, race and ethnicity, age, tenure, and housing type) compared to the national median energy burden



REGIONAL ENERGY BURDENS

We find that the national trends hold true across the nine census regions. The following are our key regional findings:

- Across all nine regions, low-income household energy burdens are 2.1–3 times higher than the median energy burden.
- The East South Central region (i.e., *Alabama, Kentucky, Mississippi, Tennessee*) has the greatest percentage of households (38%) with high energy burdens, followed by East North Central (i.e., *Illinois, Indiana, Michigan, Ohio, Wisconsin*), New England (*Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont*), and Middle Atlantic regions (i.e., *New Jersey, New York, Pennsylvania*) (all 29%).
- The gap between low-income and median energy burdens is largest in the New England, Pacific (i.e., *Alaska, California, Hawaii, Oregon, Washington*), and Middle Atlantic regions.
- The South Atlantic region (i.e., *Delaware, DC, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, West Virginia*) had the greatest number of households (6.3 million) with high burdens, followed by the East North Central (5.4 million) and Middle Atlantic (4.6 million) regions.

METRO AREA ENERGY BURDENS

National and regional patterns are mirrored in cities. The following are our key metropolitan area findings:

- Low-income households experience energy burdens at least two times higher than that of the average household in each metropolitan area included in the study.[6]
- Black and Hispanic households experience higher energy burdens than non-Hispanic white households; renters experience higher energy burdens than owners; and people living in buildings built before 1980 experience higher energy burdens than people living in buildings built after 1980 across all metro areas in the study.
- Six metro areas have a greater percentage of households with a high energy burden than the national average (25%), including Birmingham (34%), Detroit (30%), Riverside (29%), Rochester (29%), Atlanta (28%), and Philadelphia (26%).
- In five metro areas—Baltimore, Philadelphia, Detroit, Boston, and Birmingham—at least one-quarter of low-income households have energy burdens above 18%, which is three times the high energy burden threshold of 6%.

See the body of the report for additional images, maps, charts, and data on energy burden calculations nationally, regionally, and in metro areas.

Strategies to Accelerate, Improve, and Better Target Low-Income Housing Retrofits and Weatherization

Clean energy investments—such as energy efficiency, weatherization, and renewable energy—can provide a long-term, high-impact solution to lowering high energy burdens. By investing in energy efficiency and weatherization first or alongside renewable energy technologies, these measures can reduce whole-home energy use to maximize the costs and benefits of

FIGURE ES2. Strategies to improve and expand low-income energy efficiency and weatherization programs

[6] We define the "average household" energy burden as the median across all households in the sample (i.e., in each MSA).

Based on prior evidence of how weatherization reduces average customer bills, we estimate that it can reduce low-income household energy burden by 25%.

additional renewable energy generation. This report focuses on weatherization and energy efficiency as long-term solutions to reducing high energy burdens; these solutions can be combined with renewable energy investments and/or electrification strategies that reduce energy bills for additional impact. Based on prior evidence of how weatherization reduces average customer bills, we estimate that it can reduce low-income household energy burden by 25%.[7]

To ensure that more low-income and highly energy burdened households receive much-needed energy efficiency and weatherization investments, we recommend that policymakers and program implementers design policies and programs to meet the needs of highly burdened communities and set up processes for evaluation and accountability processes. This involves engaging with community members from the start, increasing funding for low-income weatherization and energy efficiency, and integrating best practices into program design and implementation. Figure ES2 depicts this actionable framework. For more information about these strategies, see the full report.

Conclusions and Next Steps

Energy affordability remains a national crisis, with low-income households, communities of color, renters, and older adults experiencing disproportionally higher energy burdens than the average household nationally, regionally, and in metro areas. This study finds that each MSA has both similar and unique energy affordability inequities. Further research can help better understand the intersectional drivers of high energy burdens and the policies best suited to improve local energy affordability. Climate change and the global pandemic also underscore the urgency in addressing high household energy burdens. As temperatures continue to rise and heat waves become more common, access to clean, affordable energy is needed more than ever to prevent indoor heat-related illnesses and deaths.

Cities, states, and utilities are well positioned to build on this research and conduct more targeted and detailed energy burden analyses, such as the Pennsylvania Public Utility Commission's study on home energy affordability for low-income customers. Studying energy burden and more broadly analyzing energy insecurity factors are first steps toward setting more targeted energy burden reduction goals and creating policies and programs that lead to more vibrant and prosperous communities.

[7] We assume 25% savings from energy efficiency upgrades based on the U.S. Department of Energy's estimate (DOE 2014) and use the median low-income household values to calculate a 25% reduction. We reduced the median low-income energy bill by 25% from $1,464 to $1,098. Using the median low-income household income of $18,000, this equates to a reduced energy burden of 6.1%. Reducing the median low-income energy burden from 8.1% to 6.1% is a 25% reduction.

Introduction

Energy insecurity—that is, the inability to adequately meet basic household heating, cooling, and energy needs over time (Hernández 2016)—is increasingly viewed as a major equity issue by policymakers, energy utilities, and clean energy and environmental justice advocates. This multidimensional problem reflects the confluence of three factors: inefficient housing and appliances, lack of access to economic resources, and coping strategies that may lead some residents to dangerously under-heat or under-cool their homes (Hernández, Aratani, and Jiang 2014).

Household energy burden—the percentage of annual household income spent on annual energy bills—is one key element contributing to a household's energy insecurity. Energy burden as a metric helps us visualize energy affordability (i.e., the ability to afford one's energy bills); identify which groups shoulder disproportionally higher burdens than others; and recognize which groups most need targeted energy-affordability- and energy-justice-related policies and investments to reduce high energy burdens. Three strategies can reduce both energy insecurity and high energy burdens: increasing household income, increasing bill payment assistance through government or utility resources, and reducing household energy use. This study discusses policy considerations that focus on the third solution of reducing excess energy use to lower high household energy burdens.

This report provides a snapshot of energy burdens nationally and in 25 of the largest U.S. metro areas. We examine median household energy burdens among groups—varying by income, housing type and age, and tenure status—as well as the percentage of households experiencing high (> 6%) and severe (> 10%) energy burdens nationally, in metro areas, and across groups (APPRISE 2005). Building on ACEEE's 2016 urban energy burden study and 2018 rural energy burden study (Drehobl and Ross 2016; Ross, Drehobl, and Stickles 2018), this report analyzes national-, regional-, and metro-level data from the U.S. Census Bureau's most recent American Housing Survey (AHS) conducted in 2017.

Local policymakers, utilities, and advocates can use this report's data and policy recommendations to better understand both which groups tend to have disproportionally higher energy burdens and how they can measure these burdens in their communities. The subsequent policy recommendations focus on low-income energy efficiency and weatherization as high-impact strategies to alleviate high energy burdens and improve overall energy affordability.

Background

Systemic Patterns and Causes of Inequities

Household access to energy is central to maintaining health and well-being, yet one in three U.S. households reported difficulty paying their energy bills in 2015 (EIA 2018). Black, Indigenous, and People of Color (BIPOC) communities often experience the highest energy burdens when compared to more affluent or white households (Kontokosta, Reina, and Bonczak 2019; Drehobl and Ross 2016; Hernández et al. 2016).[8] These communities often experience racial segregation, high unemployment, high poverty rates, poor housing conditions, high rates of certain health conditions, lower educational opportunity, and barriers to accessing financing and investment (Jargowsky 2015; Cashin 2005). Many of these characteristics are due in part to systemic racial discrimination, which has led to long-standing patterns of disenfranchisement from income and wealth-building opportunities for BIPOC communities as compared to white communities (Rothstein 2017).

[8] We use the term BIPOC in this report to describe communities that experience especially acute systemic inequities, barriers, and limited access to energy programs. By specifically naming Black and Indigenous (Native American) communities, the term BIPOC recognizes that Black and Indigenous people have historically experienced targeted policies of systemic economic exclusion, classism, and racism in the United States. It is important to recognize this history and how it has led to disproportionally high energy burdens and unique barriers to accessing clean energy technologies and investments.

Policies and practices that have led to economic and/or social exclusion in BIPOC communities include neighborhood segregation and redlining, lack of access to mortgages and other loans, mass incarceration, employment discrimination, and the legacy of segregated and underfunded schools (Jargowsky 2015; McCarty, Perl, and Jones 2019).[9] These types of systemic exclusions, underinvestments, discriminative lending practices, and limited housing choices have also limited BIPOC communities' access to efficient and healthy housing (Lewis, Hernández, and Geronimus 2019). In addition, Black communities are 68% more likely to live within 30 miles of a coal-fired power plant, and properties in close proximity to toxic facilities average 15% lower property values than those in other areas (National Research Council 2010). Black children are three times as likely to be admitted to the hospital for asthma attacks than white children (Patterson et al. 2014). According to a study by the American Association of Blacks in Energy, while Black households spent $41 billion on energy in 2009, they held only 1.1% of energy jobs and gained only 0.01% of the revenue from energy-sector profits (Patterson et al. 2014).

Systemic exclusions, under-investments, discriminative lending practices, and limited housing choices have limited Black, Indigenous, and People of Color communities' access to efficient and healthy housing.

Limited Access to Energy Programs

A growing body of research shows that BIPOC and low-income communities experience disparate access to residential energy-saving appliances and other energy efficiency upgrades. While low-income and communities of color on average consume less energy than wealthier households, they are more likely to live in less-efficient housing (Bednar, Reames, and Keoleian 2017). Researchers found that, when holding income constant, BIPOC households experience higher energy burdens than non-Hispanic white households (Kontokosta, Reina, and Bonczak 2019). BIPOC and low-income communities also may experience higher costs when investing in energy-efficient upgrades. For example, a study based in Detroit found that energy-efficient lightbulbs were less available in high-poverty areas and smaller stores, and when they were available, they were more expensive than in other areas (Reames, Reiner, and Stacey 2018).

Others have found that untargeted utility-administered energy efficiency programs do not effectively reach BIPOC and low-income communities—particularly those living in multifamily buildings (Frank and Nowak 2016; Samarripas and York 2019). Low-income communities face economic, social, health and safety, and information barriers that impact their ability to access programs, and many programs fail to address these barriers through specific targeting practices. Limited access to energy efficiency resources and investments coupled with lower incomes increase the proportion of income that low-income and BIPOC households spend on energy bills (Jessel, Sawyer, and Hernández 2019; Berry, Hronis, and Woodward 2018).

Where utilities do administer programs targeted at low-income customers, participant needs far exceed available resources. Reames, Stacy, and Zimmerman (2019) found that 11 large investor-owned utilities across six states have distributional disparities in low-income investments; that is, they do not spend energy efficiency dollars proportionally on programs designed to reach low-income populations. A 2018 report found that only 6% of all U.S. energy efficiency spending in 2015 was dedicated to low-income programs (EDF APPRISE 2018). Most states require that utility energy efficiency program portfolios be cost effective, often using tests that focus mostly on direct economic costs to the utility (Woolf et al. 2017; Hayes, Kubes, and Gerbode 2020). This requirement places an additional burden on utilities, states, and local governments that invest in programs that serve low-income communities because it does not account for nonenergy and additional health, economic, and community benefits in program planning and evaluations.

Definition and Drivers of High Energy Burdens

High energy burdens are often defined as greater than 6% of income, while *severe energy burdens* are those greater than 10% of income (APPRISE 2005).[10] Past research found that low-income, Black, and Hispanic communities, as well as older adults, renters, and those residing in low-income multifamily buildings experienced disproportionally higher energy burdens than other households (Drehobl and Ross 2016; Ross, Drehobl, and Stickles 2018).

[9] *Redlining* is the discriminatory practice of fencing off areas in which banks would avoid investments based on community demographics. Redlining was included in local, state, and federal housing policies for much of the 20th century. For more information on historical forms of economic and social exclusion, see *The Color of Law: A Forgotten History of How Our Government Segregated America* by Richard Rothstein.

[10] Researchers estimate that housing costs should be no more than 30% of household income, and household energy costs should be no more than 20% of housing costs. This means that affordable household energy costs should be no more than 6% of total household income.

TABLE 1. Key drivers of high household energy burdens

Drivers	Examples of factors that affect energy burden
Physical	Housing age (i.e., older homes are often less energy efficient)
	Housing type (e.g., manufactured homes, single family, and multifamily)
	Heating and cooling system (e.g., system type, fuel type, and fuel cost)
	Building envelope (e.g., poor insulation, leaky roofs, inefficient and/or poorly maintained poorly maintained heating and cooling systems (HVAC), and/or inadequate air sealing)
	Appliances and lighting efficiency (e.g., large-scale appliances such as refrigerators, washing machines, and dishwashers)
	Topography and location (e.g., climate, urban heat islands)
	Climate change and weather extremes that raise the need for heating and cooling
Socioeconomic	Chronic economic hardship due to persistent low income
	Sudden economic hardship (e.g., severe illness, unemployment, or disaster event)
	Inability to afford (or difficulty affording) up-front costs of energy efficiency investments
	Difficulty qualifying for credit or financing options to make efficiency investments due to financial and other systemic barriers
	Systemic inequalities relating to race and/or ethnicity, income, disability, and other factors
Behavioral	Information barriers relating to available bill assistance and energy efficiency programs and relating to knowledge of energy conservation measures
	Lack of trust and/or uncertainty about investments and/or savings
	Lack of cultural competence in outreach and education programs
	Increased energy use due to occupant age, number of people in the household, health-related needs, or disability
Policy-related	Insufficient or inaccessible policies and programs for bill assistance, energy efficiency, and weatherization for low-income households
	Utility rate design practices, such as high customer fixed charges, that limit customers' ability to respond to high bills through energy efficiency or conservation

Source: Updated from Ross, Drehobl, and Stickles 2018

Drivers of high household energy burdens are often the result of the systemic factors, barriers, and challenges that these households face. Previous research identified drivers that can raise energy burdens, including the dwelling's physical structure, the resident's socioeconomic status and behavioral patterns, and the availability of policy-related resources (Drehobl and Ross 2016; Ross, Drehobl, and Stickles 2018). Table 1 shows an updated list of key drivers of high energy burdens.

ENERGY INEFFICIENCY AS A DRIVER OF HIGH ENERGY BURDENS

While low incomes are a substantial factor driving higher energy burdens, inefficient housing is also a contributor. According to the 2017 AHS data, 9% of total U.S. households completed an energy-efficient improvement in the past two years, but only 17% were low-income households (Census Bureau 2019). Low-income households (≤ 200% of the federal poverty level [FPL]) make up about 30% of the population, which means that they are underrepresented in households completing energy efficiency upgrades and thus are not proportionally accessing and benefiting from these investments.

Additional research examining energy benchmarking data in a few major cities has found that households from both the lowest- and highest-income brackets had the highest *energy use intensity* (EUI)—that is, they had the highest energy consumption per square foot. While consumption behaviors are regarded as the driver for high EUI among higher-income households, the researchers point to inefficient heating and lighting infrastructure to help explain the high EUI among low-income households (Kontokosta, Reina, and Bonczak 2019). High-income households use large amounts of energy to power larger homes—as well as more electronics and devices that use large amounts of energy—while low-income households tend to use fewer, less-efficient devices that require relatively large amounts of energy due to the inefficiency of the dwelling or the appliance itself. Therefore, household inefficiencies rather than inefficient behaviors tend to lead to higher energy use and expenditures for low-income households. Generally, energy efficiency investments can allow households to engage in the same activity while using less energy, thus reducing high energy burdens and improving comfort, health, and safety.

Adverse Effects of High Energy Burdens

Our comprehensive evaluation of energy burden research reveals both that low-income households spend, on average, a higher portion of their income on energy bills than other groups, and that energy burdens are also higher for communities of color, rural communities, families with children, and older adults (Brown et al. 2020; Lewis, Hernández, and Geronimus 2019; Reames 2016; Hernández et al. 2016; Drehobl and Ross 2016; Ross, Drehobl, and Stickles 2018). Energy burden is one indicator to measure energy insecurity, and high energy burdens are associated with inadequate housing conditions and have been found to affect physical and mental health, nutrition, and local economic development.

EXCESSIVE ENERGY COST CAN IMPACT RESIDENTS' HEALTH AND COMFORT.

Researchers have found that many households with high energy burdens also live in older, inefficient, and unhealthy housing. Inefficient housing is associated with other health impacts, such as carbon monoxide poisoning, lead exposure, thermal discomfort, and respiratory problems such as asthma and chronic obstructive pulmonary disease (COPD); it is also associated with the potential for hypothermia and/ or heat stress resulting from leaky and/or unrepaired heating and cooling equipment (Brown et al. 2020; Norton, Brown, and Malomo-Paris 2017).

Households experiencing energy insecurity may forego needed energy use to reduce energy bills, forcing them to live in uncomfortable and unsafe homes. Hernández, Phillips, and Siegel (2016) found that half of the study's participants who experienced high monthly utility bills engaged in coping strategies such as using secondary heating equipment (i.e., stoves, ovens, or space heaters) to compensate for inefficient or inadequate heating systems. Employing this coping measure can compromise resident safety and comfort, and it may increase exposure to toxic gases. Teller-Elsberg et al. (2015) found that excess winter deaths potentially caused by fuel poverty kill more Vermonters each year than car crashes. In addition, according to the Residential Energy Consumption Survey, one in five U.S. households reported reducing or forgoing necessities such as food or medicine to pay an energy bill (EIA 2018). These tradeoffs can impact long-term health and well-being.

Climate change, rising temperatures, and subsequent cooling demands will continue to exacerbate household energy burdens—and prove deadly for some. In Maricopa County, Arizona—one of the hottest regions in the southwest—more than 90% of residents have access to a cooling system, yet up to 40% of heat-related deaths occur indoors (Maricopa County Department of Public Health 2020). A recent survey of homebound individuals found that one-third faced limitations on home cooling system use, with the overwhelming majority (81%) citing the "cost of bills" as a contributing factor (Maricopa County Department of Public Health 2016). As residents are increasingly forced to weigh the cost of properly cooling their homes, high energy burdens will likely become an even greater public health priority in the years to come.

HIGH ENERGY BURDENS IMPACT MENTAL HEALTH OF RESIDENTS.

High energy burdens can have mental health impacts—such as chronic stress, anxiety, and depression—associated with fear and uncertainty around access to energy, the complexities of navigating energy assistance programs, and the inability to control energy costs (Hernández, Phillip, and Siegel 2016). In addition, Hernández (2016) found that low-income residents who were experiencing energy insecurity worried about losing their parental rights as they struggled to maintain essential energy services, such as lighting, in their homes.

HIGH ENERGY BURDENS CAN LIMIT INDIVIDUALS' ABILITY TO BENEFIT FROM ECONOMIC DEVELOPMENT IN THEIR COMMUNITIES.

Households with high energy burdens are more likely to stay caught in cycles of poverty. After controlling for common predictors of poverty status such as income loss, illness, health, marital status, education, health insurance, and head of households—Bohr and McCreery (2019) found that, on average, energy-burdened households have a 175–200% chance of remaining in poverty for a longer period of time compared to nonenergy-burdened households.[11] BIPOC communities, older adults, and low-income households often experience this pernicious cycle, which includes persistent income inequality along with limited funding to invest in education or job training, and high energy burdens can perpetuate this cycle (Bohr and McCreery 2019; Lewis, Hernández, and Geronimus 2019).

Impact of COVID-19 on Energy Insecurity

As the world enters a global recession in the wake of the coronavirus pandemic, more households—especially in BIPOC communities—may have difficulty paying their energy bills due to massive job losses; reduced income; a warming climate; and higher energy bills resulting from more time at home due to stay-at-home orders and to students and adults learning and working from home, respectively. For example, in March and April 2020, the California Public Utility Commission stated that residential electricity usage increased by 15–20% compared to the previous year (CPUC 2020). Because such factors lead to higher home energy bills, energy burdens will increase for households across the United States.

Households with high energy burdens are more likely to stay caught in cycles of poverty.

COVID-19 disproportionally impacts BIPOC communities due to many of the policies that have led to systemic economic and social exclusion. These policies have led to BIPOC communities experiencing higher rates of underlying health conditions, a lack of health insurance or access to testing, and a higher likelihood of working in the service industry or in other essential worker roles that do not allow for teleworking (SAMHSA 2020; CDC 2020). COVID-19 has also impacted the ability of energy efficiency and weatherization programs to operate, and limited the mix of measures that can be installed; many energy efficiency and weatherization programs have slowed down or are on hold (Ferris 2020). Policies and programs that address energy insecurity are even more important now in the face of rising energy bills and burdens.

Given these factors, energy burdens in 2020 are likely to be much higher than the burdens we calculate in this report, which uses 2017 data. The economic situation has clearly shifted drastically since 2017. While we expect post-2020 burden trends to be similar, yet more acute, we cannot visualize the full extent of current and future energy burdens until the release of post-2020 data in the 2023 AHS, which will include data from 2021.

[11] This study does not examine the relationship between energy burden and rent burden (i.e., the percentage of income spent on housing costs). Studies have found that rent burdens are also increasing, especially for communities of color, older adults, and families (Currier et al. 2018).

Methods

This analysis builds on the methods used in ACEEE's previous two energy burden studies, *Lifting the High Energy Burden in American's Largest Cities* (Drehobl and Ross 2016) and *The High Cost of Energy in Rural America* (Ross, Drehobl, and Stickles 2018). This new study analyzes 2017 data from AHS, which is issued by the U.S. Department of Housing and Urban Development (HUD). The AHS is a biennial household-level survey by the Census Bureau that collects wide-range housing and demographic data from a nationally and regionally representative cross section of households across the United States and in a subset of metropolitan statistical areas (MSAs). The AHS includes household-level income data and energy cost data that we use as the basis of our energy burden calculations. The AHS models its energy cost data based on household characteristics ascertained through its survey and also uses data collected through the Residential Energy Consumption Survey (RECS) for a different national set of households.[12]

As we noted earlier, we define households with high energy burdens as those spending more than 6% of their income on electricity and heating fuel costs, and households with severe energy burdens as those spending more than 10% of their income on energy costs.[13] These two categories are not mutually exclusive; *severe burden* is a worse-off subset of high burden households.

[12] Beginning with the 2015 edition, the AHS stopped including questions on energy costs. Previously, the majority of these data was self-reported. As part of the 2015 AHS redesign, researchers began estimating energy costs through regression-model-based imputation. They created the utility estimation system (UES) to estimate annual energy costs using regression models developed from the RECS, which collects administrative data from suppliers on actual billing amounts. This estimate was divided by 12 to calculate average monthly energy costs. The RECS also collects some housing characteristics similar to those the AHS collects, which allows the construction of models that can then be applied to the AHS. For more on the energy cost estimation model development and decisions for the 2015 AHS, see www.huduser.gov/portal/sites/default/files/pdf/American-Housing-Survey.pdf.

[13] HUD determines affordable housing costs to be 30% of total household income. Researchers have determined that, typically, 20% of total housing expenses are energy costs. This equates to 6% of total income spent on energy bills as an affordable level (Fisher Sheehan & Colton 2020). We consider energy burdens above 6% to be high burdens, with burdens above 10% to be severe. This method is in line with other research (APPRISE 2005).

The following are our study's inclusion and exclusion criteria:

- *Electricity and heating fuels*. The study does not include water, transportation, telecommunications, or Internet costs. Although such costs can create additional monetary burdens for households, we include only electricity and heating fuel costs in our energy burden calculations.
- *Households must report household income and the amount they pay for their electricity and their main heating fuel*.[14] If households did not include all three factors, we did not include them in our analysis.

We examine energy burdens for a variety of household subsets at the national, regional, and metropolitan levels, including the following:

- *Income level*. All households that fall into low-income (≤ 200% FPL) and non-low-income (> 200% FPL) categories.[15]
- *Low-income households with vulnerable persons at home*. Low-income households with a household member over the age of 65, under the age of 6, or who has a disability.
- *Housing type and age*. Single-family, small multifamily (two to four units), large multifamily (five or more units), low-income multifamily (five or more units and ≤ 200% FPL), manufactured housing, buildings built before 1980, and buildings built after 1980.[16]
- *Tenure*: Renters and owners.
- *Race and ethnicity*. Black, Hispanic, and non-Hispanic white households. We also include Native American households in the national analysis.
- *Age*. Households with one or more adults over the age of 65.

Limitations

We included 48 MSAs in our last urban energy burden report, which used both 2011 and 2013 AHS data. This report uses only 2017 data, which limits our sample to 25 MSAs (AHS 2019). AHS includes modeled energy costs, which are determined by matching characteristics of households in the AHS to characteristics of households in the RECS. We also exclude households that do not report income, do not have a heating source, or do not pay for their heating costs. Thus, our report findings do not include data on renters who pay for their heating and/or electricity in their rent, or households with no annual income reported.

Our study does not explore causality, so we cannot determine *why* energy burdens differ across metro areas and demographic and other groups. Additional research is needed to determine the causes of disproportionate energy burdens, which can include building efficiency, income and poverty rates, and other timely economic factors. We are unable to compare trends across our energy burden reports, as this study does not explore why and how energy burdens may have changed over time.

Finally, our study includes only the 25 metro areas sampled by the AHS, which are not necessarily the best or worst performing metro areas regarding energy burdens. Ranking metro areas is thus limited since this is only a partial sample of cities. ACEEE plans to update this research with additional metro areas as more AHS data are available in the fall of 2020.

The following are the 25 MSAs with representative samples in the 2017 AHS dataset:

1. Atlanta	6. Dallas	11. Miami	16. Phoenix	21. San Francisco
2. Baltimore	7. Detroit	12. Minneapolis	17. Richmond	22. San Jose
3. Birmingham	8. Houston	13. New York City	18. Riverside	23. Seattle
4. Boston	9. Las Vegas	14. Oklahoma City	19. Rochester	24. Tampa
5. Chicago	10. Los Angeles	15. Philadelphia	20. San Antonio	25. Washington, DC

[14] AHS calculates household income as total money before taxes and other payments, including Social Security income, cash public assistance, or welfare payments from the state or local welfare office, retirement, survivor or disability benefits, and other sources of income such as veterans' payments, unemployment and/or worker's compensation, child support, and alimony. For more information, see: www2.census.gov/programs-surveys/ahs/2017/2017%20AHS%20Definitions.pdf.

[15] In ACEEE's 2016 urban energy burden report, we defined low-income as 80% of the area median income (AMI), while this report defines low-income as 200% FPL. We made this change due to data availability. The 200% FPL definition also lines up with the Weatherization Assistance Program and is the most common qualification criterion for utility-led low-income programs. Because of this, low-income data in the 2016 and 2020 reports do not use the same definitions and are therefore not directly comparable.

[16] We chose 1980 as our cutoff point as states and cities began adopting the first building energy codes in the late 1970s and early 1980s. At this time, builders around the country began to consider energy and minimal energy efficiency measures due to increasing awareness of efficiency measures and concerns about energy as a result of the energy-related economic shocks of the 1970s.

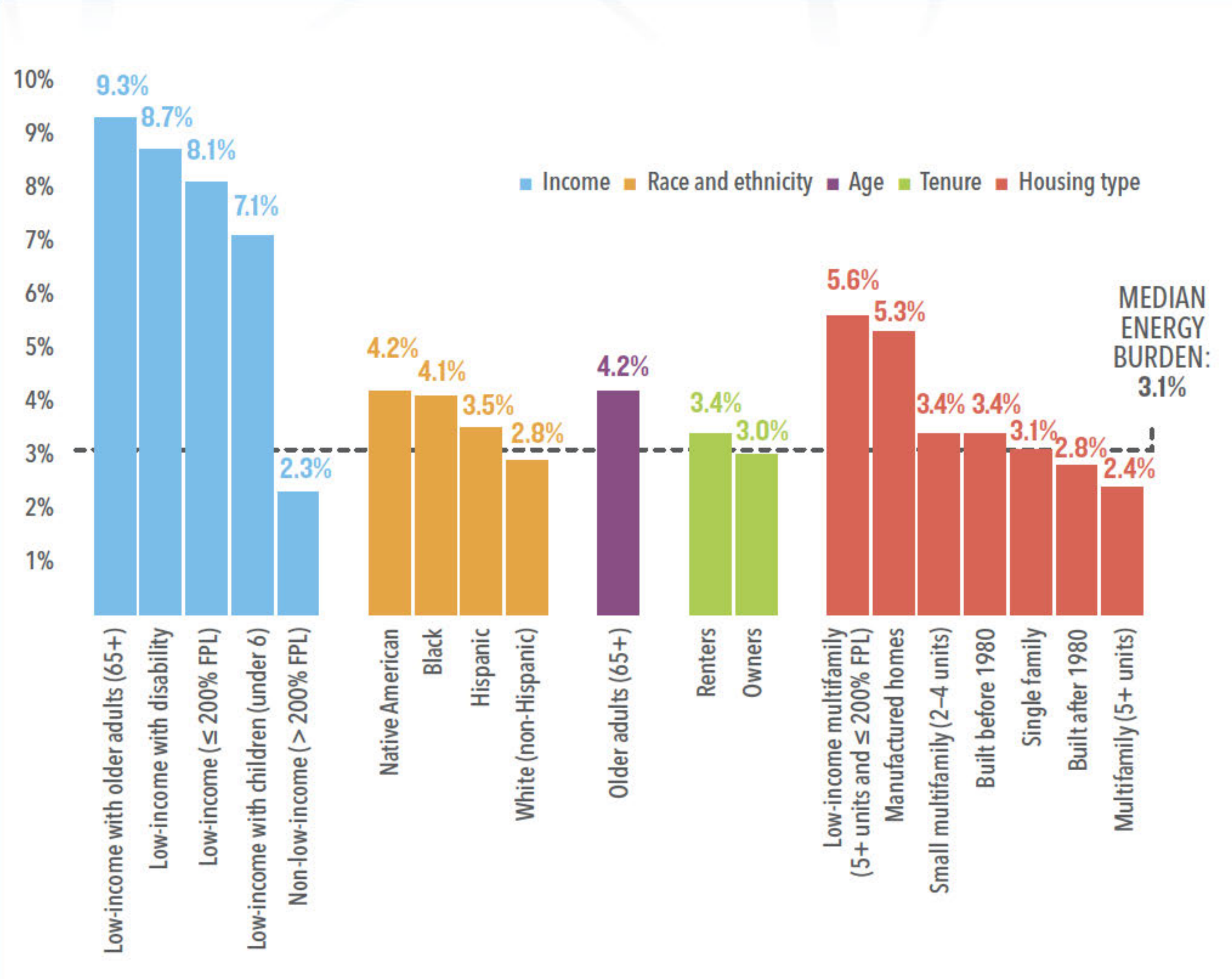
Energy Burden Findings

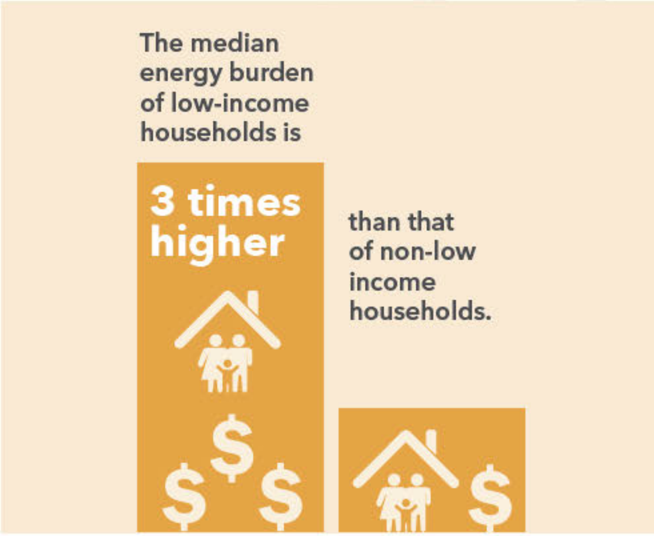
The results of this energy burden analysis reflect previous ACEEE studies in finding that nationally, regionally, and across all 25 metro areas, particular groups experience disproportionately high energy burdens. See **Appendices A** and **B** for tables including national, regional, and metro energy burden data.

National Energy Burdens

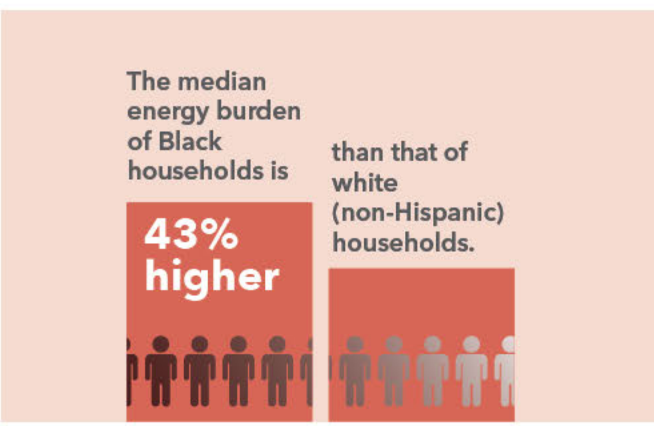
Across the nationally representative sample, we find that low-income, Black, Hispanic, renter, and older adult households have disproportionately higher energy burdens than the average household. Figure 1 shows the median energy burden for different groups nationally, across categories of income, race and ethnicity, age, tenure status, and housing type. We find that the median national energy burden is 3.1%, and that the median low-income (≤ 200% FPL) household energy burden is 3.5 times higher than the non-low-income household energy burden (8.1% versus 2.3%).

FIGURE 1. National energy burdens across subgroups (i.e., income, race and ethnicity, age, tenure, and housing type) compared to the national median energy burden





Many groups experience disproportionately high energy burdens, with low-income households having the highest energy burdens. These households have limited discretionary income and often have older, less-efficient housing stock and appliances that lead to higher energy bills. Even for cases in which monthly energy costs are similar between low-income and non-low-income households, the former devote a greater proportion of their income to these costs. Given this, reducing excess energy use in low-income households is critical for addressing energy insecurity.



We also recognize that many highly burdened groups are intersectional—that is, they face compounding, intersecting causes of inequality and injustice. For example, nearly half of the older adult population in general is economically vulnerable, as are the majority of older Black and Hispanic households (Cooper and Gould 2013). Policies and programs that focus on addressing low-income household energy burdens will likely intersect with other highly burdened groups. Further research can help identify how high energy burdens are impacted by differences in race, ethnicity, income, education, housing type, occupant age, and other factors.

NATIONAL DATA: HIGH AND SEVERE ENERGY BURDENS

Median energy burdens allow us to compare burdens between groups, yet they do not illustrate how many people experience the impacts of energy insecurity, or the degrees to which they experience it. We therefore also calculate the percentage of households that experience high and severe energy burdens for different demographic groups. Figure 2 shows the percentage of households across subgroups that experience a high energy burden (above 6%), along with the total number of households experiencing a high energy burden. Figure 2 also indicates the percentage of those households that experience a severe energy burden (above 10%).

Nationally, more than 25% (30.6 million) of all households experience a high energy burden, and about 50% (15.9 million) of all households that experience a high energy burden have a severe energy burden. These burdens are even more acute for low-income households, of which 67% (25.8 million) experience a high energy burden and 60% (15.4 million) of those experience a severe energy burden. **Appendix B** includes high and severe energy burden percentages and total households that experience a high and severe

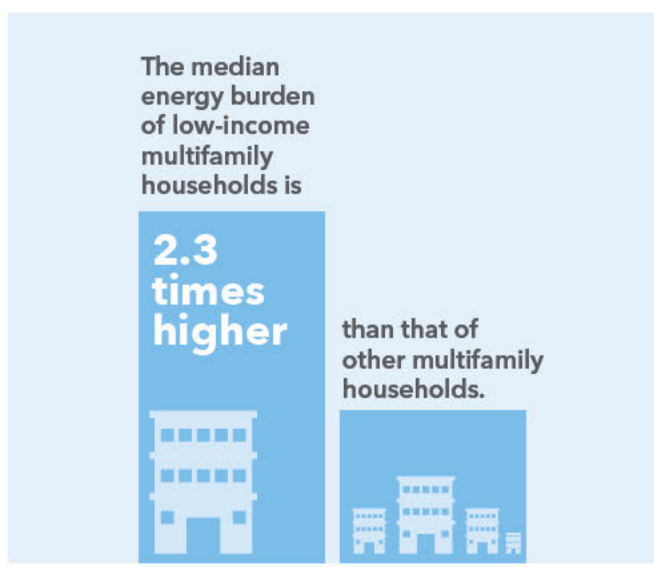
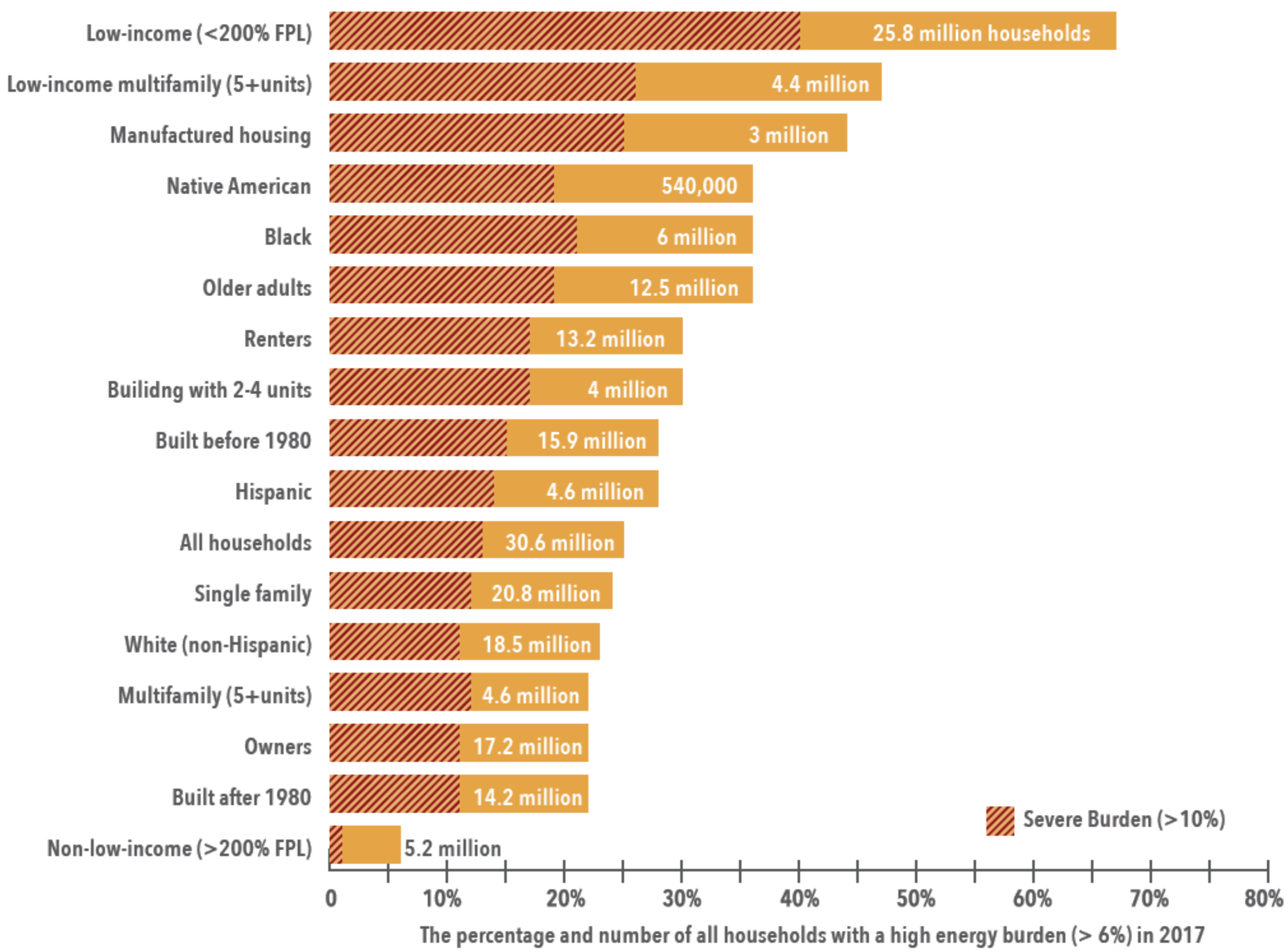


FIGURE 2. The percentage and number of households nationally with a high energy burden (> 6%) across different subgroups in 2017

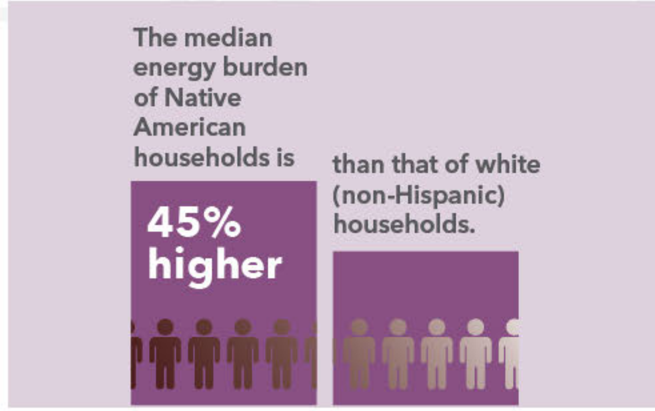


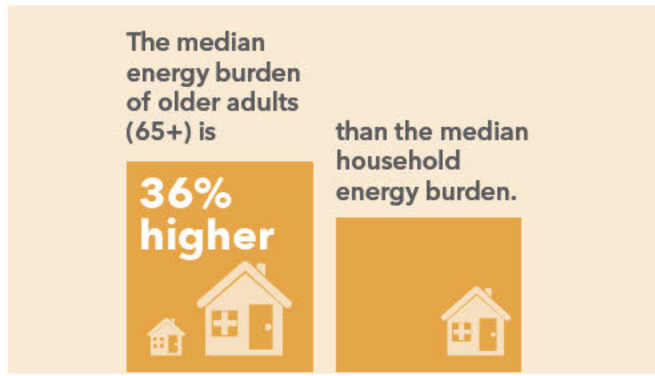
Note: High and severe energy burdens are not mutually exclusive, meaning that the number of households experiencing a severe burden are also counted in the percentage that experience high burdens. All severe energy burdens (> 10%) also fall into the high burden category (> 6%). The red and orange bars in figure 2 sum to the total high energy burdened households, and the number of households is the total that experience a high energy burden.

burden nationally, regionally, and in each MSA across all households and across low-income, Black, Hispanic, older adult, and renting households.

As figure 2 illustrates, U.S. residents experience high and severe energy burdens at different rates depending on factors such as income, occupant age, race, and tenure. Almost 50% of low-income multifamily residents; 36% of Black, Native American, and older adult households; 30% of renters; and 28% of Hispanic households experience a high energy burden.

Many households also have severe energy burdens, spending more than 10% of their income on energy. For example, 21% of Black households experience severe energy burdens as compared to 1% of non-low-income and 9% of non-Hispanic white households. For context, households with severe energy burdens spend at least three times more of their income on home energy bills than the median household.





Regional Energy Burdens

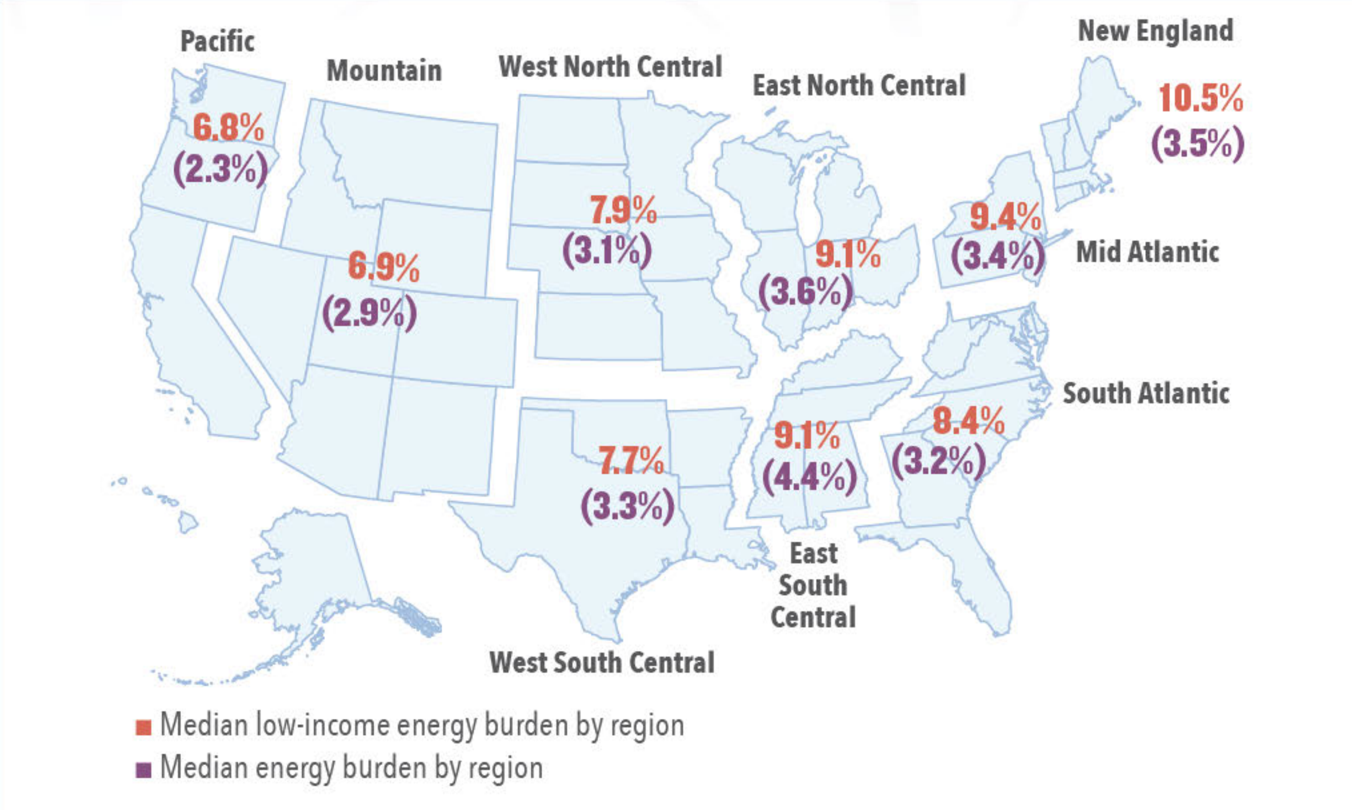
National patterns play out across all regions, where low-income, Black, and Hispanic households; renters; manufactured housing residents; and older adults all have disproportionately higher energy burdens than each region's average household. Table 2 shows the states in each census region in the study.

Across all nine regions, low-income household energy burdens are 2.1–3 times higher than the median energy burden. The gap between low-income and median energy burdens is largest in the New England, Pacific, and Mid-Atlantic regions (3.0, 2.9, and 2.8 times higher, respectively). Figure 3 illustrates low-income energy burdens and the median energy burden across the nine census regions.

TABLE 2. States within each census region

Region	States
New England	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont
Middle Atlantic	New Jersey, New York, Pennsylvania
East North Central	Illinois, Indiana, Michigan, Ohio, Wisconsin
West North Central	Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, South Dakota
South Atlantic	Delaware, DC, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, West Virginia
East South Central	Alabama, Kentucky, Mississippi, Tennessee
West South Central	Arkansas, Louisiana, Oklahoma, Texas
Mountain	Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming
Pacific	Alaska, California, Hawaii, Oregon, Washington

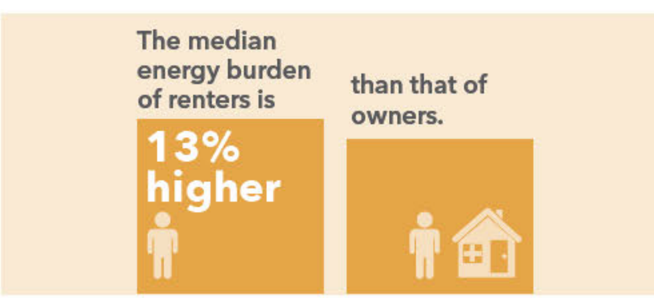
FIGURE 3. Median low-income (< 200% FPL) energy burdens by region (red) compared to median energy burdens by region (purple)



REGIONAL DATA: HIGH AND SEVERE ENERGY BURDENS

Figure 4 shows the percentage and total number of households that experience high and severe energy burdens in each region.

The percentage and total number of households that experience a high energy burden vary across regions. The East South Central region has the greatest percentage of households with high energy burdens (38%), followed by East North Central, New England, and Middle Atlantic regions, all with 29%. The South Atlantic region had the greatest number of households (6.27 million) with high burdens, followed by the East North Central (5.40 million) and Middle Atlantic (4.57 million) regions. See **Appendix B** for the total number of highly burdened households across different groups in each region.

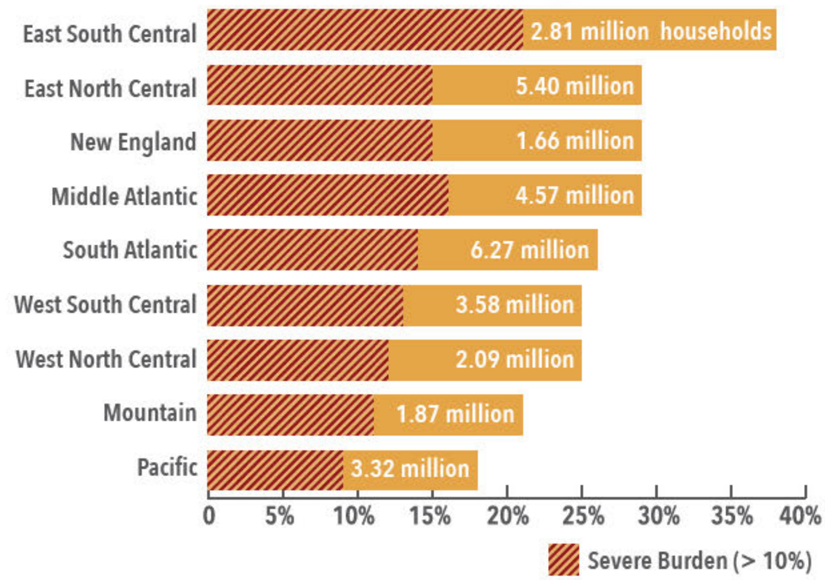


Metro Area Energy Burdens

Across the select MSAs—which represent 38% of all households nationally—low-income households, low-income multifamily households, and older adult households are the most energy burdened groups. Groups with the lowest energy burdens are non-low-income, those living in buildings built after 1980, and those living in market-rate multifamily housing. Table 3 includes the median energy burdens for the most highly burdened groups in each metro area; **Appendices A** and **B** offer more details.[17]

[17] **Appendix A** includes national, regional, and metro area sample sizes, median energy burdens, median incomes, median monthly bills, upper-quartile energy burdens, percentage with a high burden, and percentage with a severe burden. **Appendix A** also includes median and upper-quartile energy burdens for subgroups nationally, regionally, and in metro areas, including low-income, low-income with older adults, low-income with a child under 6, low-income with disability, low-income multifamily, non-low-income, Black, Hispanic, non-Hispanic white, older adult, renters, owners, multifamily, built before 1980, and built after 1980. **Appendix B** includes the number of households nationally, regionally, and in metro areas that experience a high or severe energy burden.

FIGURE 4. The percentage and number of all households with a high energy burden (> 6%) in each region in 2017



The percentage and number of all households with a high energy burden (> 6%) in 2017

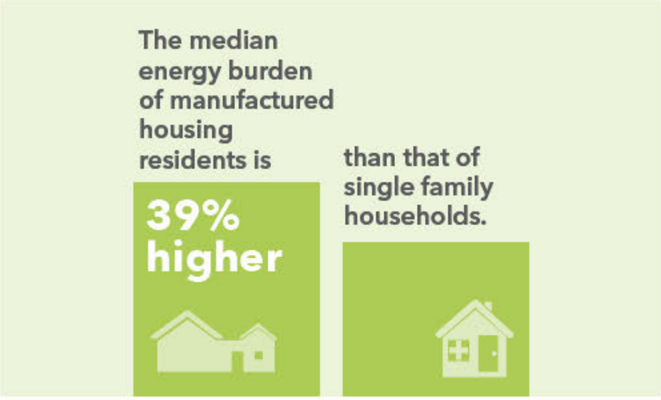


Figure 5 includes the energy burdens at the median and upper quartile, showing that 50% of households in each city experience a burden above the median and 25% experience a burden above the upper quartile. For example, in Baltimore, 25% of low-income households experience an energy burden above 21.7%, which is seven times the national median burden. In five cities—Baltimore, Philadelphia, Detroit, Boston, and Birmingham—a quarter of low-income households have energy burdens above 18%, which is three times the 6% high energy burden threshold.

Across the 25 MSAs, low-income households experience energy burdens at least two times higher than the average household in all cities. In all metro areas, Black and Hispanic households experience higher energy burdens than non-Hispanic white households. Renters and people living in buildings built before 1980 experience higher energy burdens than owners in almost all metro areas in the study.

Median energy burdens do not tell the whole energy affordability story, as half of households in each group experience a higher energy burden than the median.

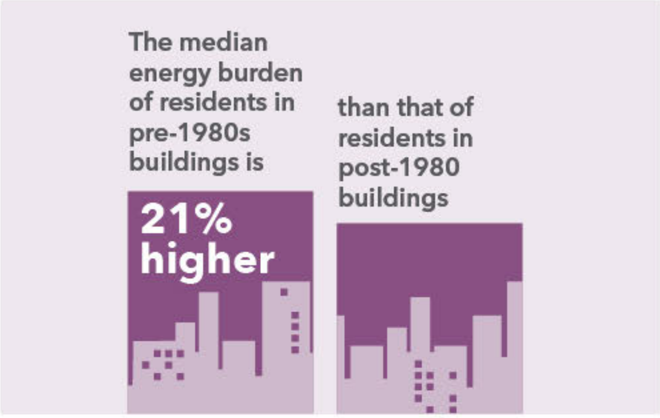
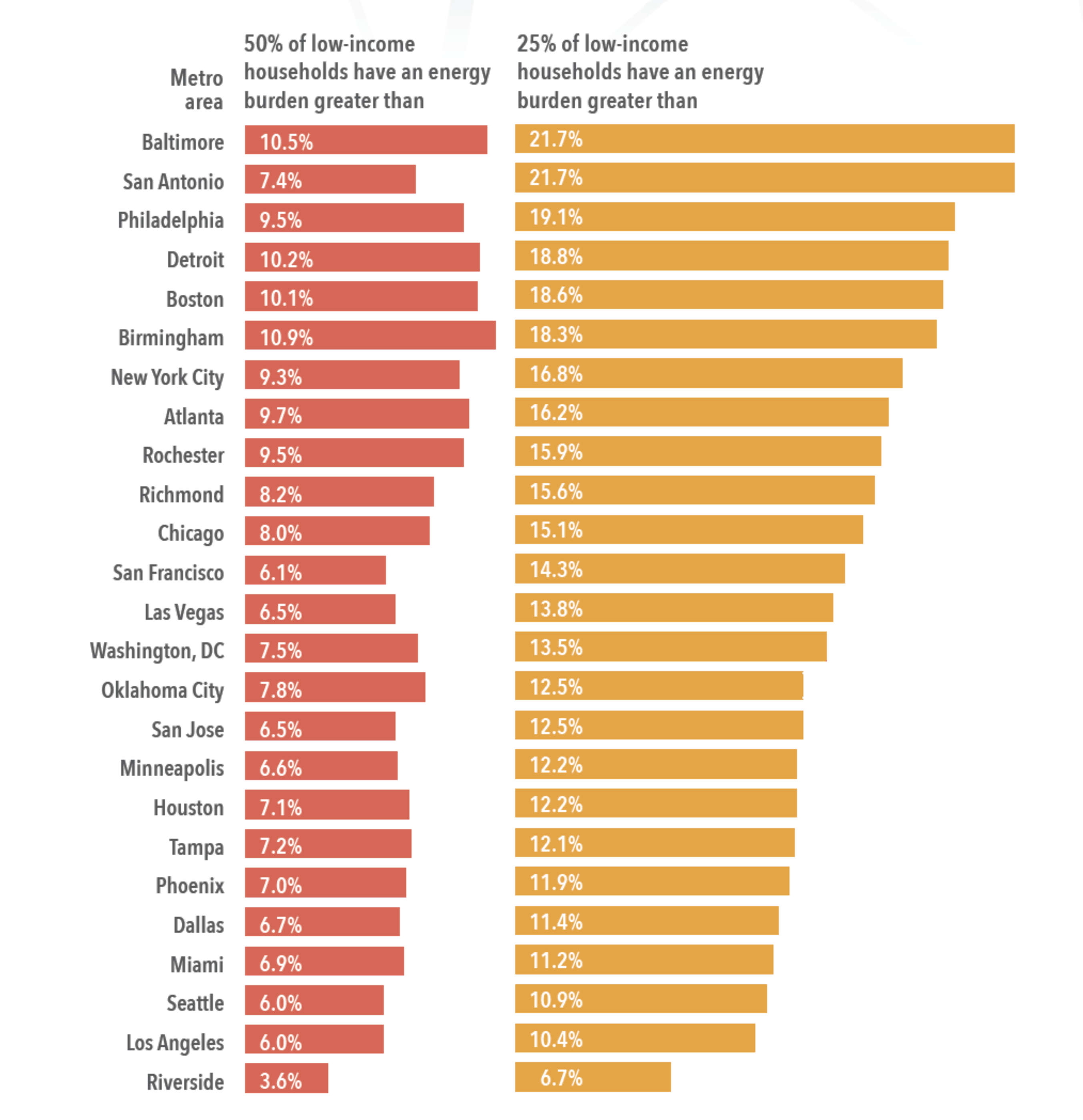


TABLE 3. Median energy burdens in metro areas for all households and highly impacted groups, including low-income, Black, Hispanic, older adult (65+), renters, low-income multifamily residents, and those residing in buildings built before 1980

Metro area	All households	Low-income (≤ 200% FPL)	Black	Hispanic	Older adults (65+)	Renters	Low-income multifamily*	Built before 1980
National data	3.1%	8.1%	4.2%	3.5%	4.2%	3.4%	3.1%	3.4%
Atlanta	3.5%	9.7%	4.1%	4.7%	5.1%	3.7%	6.6%	4.5%
Baltimore	3.0%	10.5%	3.8%	3.3%	4.1%	3.2%	2.5%	3.6%
Birmingham	4.2%	10.9%	5.6%	4.8%	5.8%	5.2%	6.8%	5.1%
Boston	3.1%	10.1%	3.7%	3.6%	4.4%	3.2%	6.6%	3.2%
Chicago	2.7%	8.0%	4.1%	3.0%	3.7%	3.1%	6.4%	2.9%
Dallas	2.9%	6.7%	3.3%	3.8%	3.8%	2.9%	5.0%	3.5%
Detroit	3.8%	10.2%	5.3%	4.5%	5.2%	4.6%	6.0%	4.3%
Houston	3.0%	7.1%	3.5%	3.4%	4.1%	3.3%	5.8%	3.4%
Las Vegas	2.8%	6.5%	3.2%	3.0%	3.4%	3.0%	5.3%	3.6%
Los Angeles	2.2%	6.0%	3.6%	2.6%	3.2%	2.4%	4.8%	2.3%
Miami	3.0%	6.9%	3.4%	3.1%	4.2%	3.1%	5.5%	3.3%
Minneapolis	2.2%	6.6%	2.6%	2.7%	3.0%	2.3%	4.3%	2.5%
New York City	2.9%	9.3%	3.6%	3.8%	4.2%	3.3%	8.0%	3.0%
Oklahoma City	3.3%	7.8%	3.9%	4.2%	4.0%	3.9%	6.5%	3.8%
Philadelphia	3.2%	9.5%	4.4%	5.2%	4.4%	3.9%	6.5%	3.6%
Phoenix	3.0%	7.0%	3.2%	3.6%	4.0%	2.8%	4.6%	3.6%
Richmond	2.6%	8.2%	3.4%	2.9%	3.5%	2.9%	5.0%	3.1%
Riverside	3.6%	8.7%	3.9%	3.7%	5.1%	4.0%	6.1%	4.3%
Rochester	3.8%	9.5%	5.1%	5.4%	4.8%	4.3%	6.0%	4.0%
San Antonio	3.0%	7.4%	3.1%	3.4%	4.1%	3.1%	4.8%	3.9%
San Francisco	1.4%	6.1%	2.4%	1.2%	2.4%	1.4%	4.9%	1.4%
San Jose	1.5%	6.5%	1.8%	1.9%	2.4%	1.5%	4.7%	1.6%
Seattle	1.8%	6.0%	2.3%	2.0%	2.4%	1.8%	4.1%	2.0%
Tampa	2.8%	7.2%	3.6%	3.5%	3.8%	2.8%	4.9%	3.3%
Washington, DC	2.0%	7.5%	2.9%	2.7%	2.9%	2.0%	5.2%	2.3%

* Low-income multifamily households are below 200% FPL and in a building with five or more units.

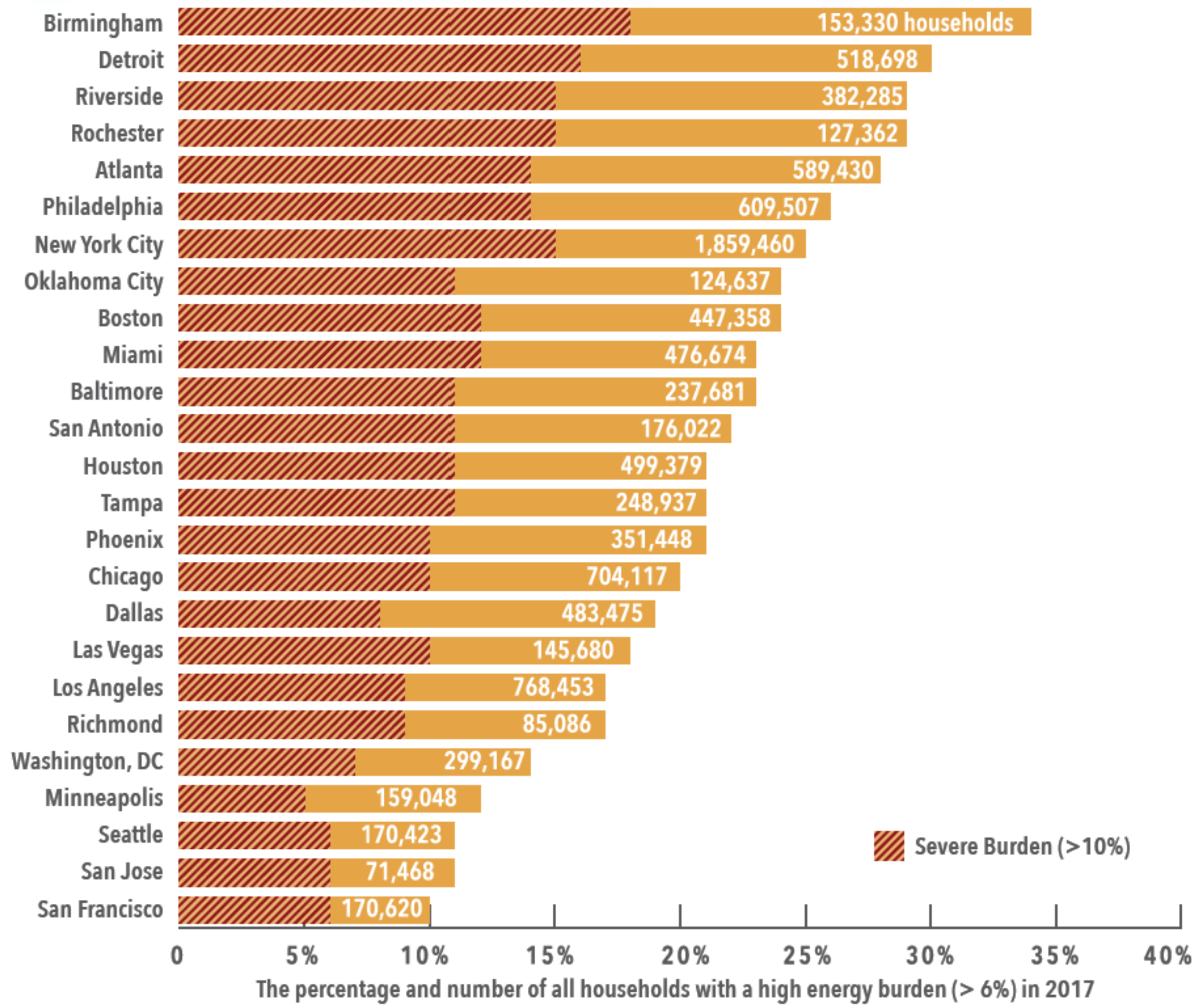
FIGURE 5. Energy burden experienced by 50% and 25% of low-income households in 25 metro areas



METRO DATA: HIGH AND SEVERE ENERGY BURDENS

The percentage of households experiencing a high energy burden varied across the select metro areas, with up to one-third of residents in some cities facing a high energy burden. Figure 6 shows the percentage and total number of households in each metro area that experience high and severe energy burdens. Six metro areas have a greater percentage of households with a high energy burden than the national average (25%), including Birmingham (34%), Detroit (30%), Riverside (29%), Rochester (29%), Atlanta (28%), and Philadelphia (26%).

FIGURE 6. The percentage and number of all households with a high energy burden (> 6%) in each of the 2017 AHS MSAs



Appendix B includes data on high and severe energy burdens in each metro area in our sample. In nine metro areas, 12% or more of households experienced a severe energy burden, spending more than 10% of their income on energy bills; among these are 1.1 million households in New York City, 333,000 in Philadelphia, and 288,000 in Atlanta.

As these findings illustrate, high and severe energy burdens are both a national and a local challenge. Even though some metro areas have lower percentages of households with high energy burdens than the national average, each city has tens to hundreds of thousands of households with high energy burdens. In addition, both the national energy burden trends and the metro-level trends show similar patterns of energy burden vulnerability for specific groups and are therefore likely reflected in other metro areas nationally as well. This indicates that both the metro areas studied and other cities have energy burden disparities in their communities. They also have opportunities to create policy and programs to lower these energy burdens for their residents.

By focusing on the needs of those who are disproportionally burdened—particularly at the intersection of criteria such as of low-income, communities of color, older adults, and renters—policymakers can set policies and create programs that have the greatest impact on energy insecurity. As they do so, they should recognize that many households—especially those with high energy use due to building inefficiencies—experience much higher than average energy burdens. These households are therefore likely to need targeted and long-lasting interventions, such as energy efficiency and weatherization, to achieve long-term affordability.

Low-Income Weatherization Can Reduce High Energy Burdens

Energy efficiency and weatherization provide a long-term solution to reducing high energy burdens, while also complementing bill payment assistance and programs aimed at energy-saving education and behavior change. *Weatherization* refers to programs that address the efficiency of the building envelope and building systems (such as unit heating, cooling, lighting, windows, and water heating) through energy audits; these audits identify cost-effective energy efficiency upgrades provided through energy efficiency programs. Other low-income energy efficiency programs may include additional measures such as appliance replacements, efficient lighting, and health and safety measures. While these recommendations focus on weatherization and energy efficiency as a long-term solution to reducing high energy burdens, these investments can be combined with renewable energy technologies and/or electrification strategies to further reduce energy bills.

Energy efficiency programs and investments that provide comprehensive building upgrades—such as insulation, air sealing, heating and cooling systems, appliances, lighting, and other baseload measures—can strongly impact long-term energy affordability, as low-income households tend to live in older buildings and have older, less-efficient appliances than higher income households (Cluett, Amann, and Ou 2016). Research suggests that weatherization measures can reduce energy use by 25–35% (DOE 2014, 2017; DOE 2011). Assuming a 25% reduction in energy use and using the 2017 AHS data, we estimate that energy efficiency and weatherization can reduce the energy burden of the average low-income household by 25%.[18]

Low-income energy efficiency and weatherization programs are especially important in the wake of the economic recession and pandemic. These programs can both reduce high energy burdens and help stimulate the economy through local job creation and workforce development. Policies that accelerate investment in, improve the design of, and better target low-income energy efficiency, weatherization, and housing retrofit programs can have a high impact on long-term energy affordability.

[18] We assume a 25% savings from energy efficiency upgrades based on the U.S. Department of Energy's estimate (DOE 2014) and use the median low-income household values to calculate a 25% reduction. We reduced the median low-income energy bill by 25% from $1,464 to $1,098. Using the median low-income household income of $18,000, this equates to a reduced energy burden of 6.1%. Reducing the median low-income energy burden from 8.1% to 6.1% is a 25% reduction. Following this same methodology, our 2016 metro energy burden report estimates a 30% reduction based on the 2011 and 2013 AHS data.

Strategies to Accelerate, Improve, and Better Target Low-Income Housing Retrofits, Energy Efficiency, and Weatherization

Many local and state governments, utilities, and community-based organizations have already begun to identify energy efficiency as a key strategy for lowering high energy burdens. To date, we have identified nine cities (Atlanta, Cincinnati, Houston, Minneapolis, New Orleans, Oakland, Philadelphia, Pittsburgh, Saint Paul) and six states (Colorado, New Jersey, New York, Oregon, Pennsylvania, Washington) that have set energy-burden-focused policies, goals, or programs with energy efficiency as a key component (see **Appendix C**). For example, the State of Oregon's *Ten-Year Plan to Reduce the Energy Burden in Oregon Affordable Housing* states that its goal is to "reduce the energy burden on the low-income population in Oregon, while prioritizing energy efficiency to achieve that reduction" (OR DOE, OR PUC, and OHCS 2019). At the city level, Philadelphia's Clean Energy Vision Plan set a goal to eliminate the energy burden for 33% of Philadelphians. To accomplish this, the city has designed and funded multiple pilot programs to reduce high energy use in multifamily and single-family buildings. See **Appendix C** for more information on energy-burden-focused city- and state-led actions.

FIGURE 7. Key strategies to lower high energy burdens by better targeting low-income energy efficiency programs, ramping up investment, and improving program design and best practices

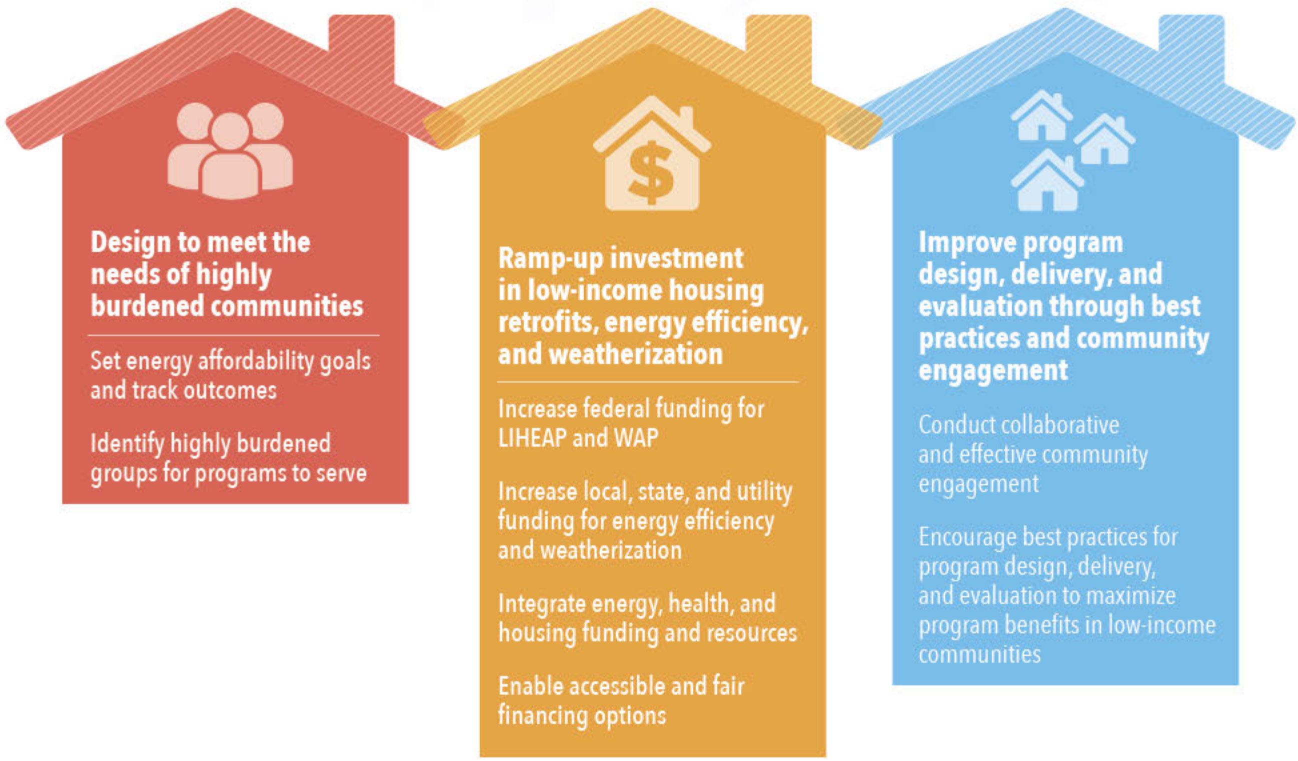


Figure 7 illustrates the key strategies to design programs to meet the needs of highly burdened communities, increase funding, and improve program design to have the greatest impact.

Design to Meet the Needs of Highly Burdened Communities

Focusing low-income energy efficiency and weatherization investment on residents with the highest burdens can greatly alleviate energy insecurity. Local and state governments and utilities can conduct more granular and detailed energy insecurity studies or analyses to help identify which local communities have the highest burdens. They can also use other energy equity and justice-related metrics and indicators to target resources to and investment in these communities. One tool for doing this analysis is the U.S. Department of Energy (DOE) Low Income Energy Affordability Data (LEAD) tool (see text box 1). Policymakers and program implementers can use a community-based approach to develop programs to invest in communities with high burdens. Cities and states can also set energy affordability goals and policies, and then track outcomes to ensure that the communities most impacted by energy insecurity receive the benefits of energy efficiency investments.

TEXT BOX 1. ENERGY BURDEN ASSESSMENTS: LOW INCOME ENERGY AFFORDABILITY DATA (LEAD) TOOL

The Department of Energy's Low Income Energy Affordability Data Tool (LEAD), developed with the National Renewable Energy Laboratory, aims to help states, communities, and other stakeholders create better energy strategies and programs by improving their understanding of low-income housing and community energy characteristics. LEAD is a web-accessible interactive platform that allows users to build their own state, county, and census tract and city profiles with specific household energy characteristics associated with various income levels and housing type, vintage, and tenure. The tool provides three principal metrics—energy burden, annual average housing energy costs, and housing counts—along with map and chart-based visualizations (Ma et al. 2019). States and local governments have begun using the LEAD tool in planning. For example, New Jersey cited its use of LEAD in the development of its new Office of Clean Energy Equity (New Jersey Legislature 2020).

LEAD is available for free at energy.gov/eere/slsc/maps/lead-tool.

SET ENERGY AFFORDABILITY GOALS AND TRACK OUTCOMES

State and local policymakers can set energy affordability and energy burden goals as a first step to addressing energy insecurity in their communities. Examples of such goals include reducing energy burdens by certain percentages, lowering energy burdens for all households to a certain threshold, or targeting resources toward individuals with high energy burdens. By focusing on the needs of those who are disproportionally burdened—particularly at the intersection of criteria such as income, race and ethnicity, and age—policymakers can set policies and create programs that have the greatest impact on addressing energy insecurity. Table 4 lists cities that have established energy burden and affordability goals. **Appendix C** includes additional city and state energy burden policies.

To establish energy burden goals, cities, states, and utilities can conduct baseline studies to understand the state of energy burdens, poverty, housing, and access to energy efficiency investments in their communities. They can then establish an appropriate goal and strategies to accomplish that goal.

Coordinating goal setting with other state and local priorities can help cities to streamline their efforts. Some cities—such as Minneapolis and New Orleans—include energy burden goals in their climate action plans as a strategy to reduce greenhouse gas emissions and achieve more equitable outcomes. States such as New York have also used energy burdens in statewide energy affordability policy plans.

Energy burden maps and visualizations are a useful tool for cities and states to achieve more equitable and affordable energy in their communities, move resources toward overburdened communities, and address other climate and equity goals. The DOE's LEAD tool provides one way to create energy burden visualizations. Plans should include specific strategies for lowering high energy burdens, as well as methods and strategies to track iterative progress.

In addition to goals, some cities have begun using energy burden as an equity indicator metric. For example, the city of Oakland includes energy cost burden as a metric in its *2018 Equity Indicators* report (City of Oakland 2018) to measure equity within essential housing services. The city found that energy burdens were higher for Black, Hispanic, and Asian households in the city as compared to white households. Similarly, the Minneapolis Climate Action Plan indicates that reporting on plan progress should also include equity indicators to measure whether energy burden reductions are equitable (City of Minneapolis 2013). Text box 2 offers examples of how governors and policymakers in four states—Pennsylvania, New York, Oregon, and Washington—created goals and policies around energy burdens to address energy insecurity in their states. To date, energy burden goals are largely set and acted upon by climate and energy officials at the city and state level. Such metrics and goals are rarely part of larger

TABLE 4. Cities with energy burden goals and strategies

City	Description	Data source
Atlanta	The Resilience Strategy includes action to lift energy burden on 10% of Atlanta households.	City of Atlanta 2017
Cincinnati	The Green Cincinnati Plan set a goal to reduce household energy burdened by 10% compared to current levels.	City of Cincinnati 2018
Houston	The Climate Action Plan includes a goal to promote weatherization programs to reduce residential energy consumption and focus on reducing energy burdens of low-income populations.	City of Houston 2020
Minneapolis	The Climate Action Plan states that the city will prioritize neighborhoods with high energy burdens for strategy implementation.	City of Minneapolis 2013
New Orleans	The Climate Action Plan includes two strategies to reduce the high energy burdens of the city's residents.	City of New Orleans 2017
Philadelphia	The Clean Energy Vision Plan set a goal to eliminate the energy burden for 33% of Philadelphians.	City of Philadelphia 2018
Saint Paul	The city set a 10-year goal to reduce resident energy burden so that no household will spend more than 4% of its income on energy bills.	City of Saint Paul 2017

TEXT BOX 2. CASE STUDIES: STATE-LED ENERGY AFFORDABILITY EFFORTS

New York Energy Affordability Goal. In 2016, Governor Andrew M. Cuomo became one of the first U.S. government officials to issue a policy aimed at addressing high energy burdens. Through the state's first ever Energy Affordability policy, he aims to ensure that no New Yorker spends more than 6% of their household income on energy (New York 2016). New York continues to explore pathways to reducing energy burden to 6% for all New Yorkers through a combination of enhanced bill assistance, energy efficiency, and increased coordination among state agencies responsible for energy, bill assistance, and affordable housing.

Oregon's Strategies to Achieve Affordability. Issued by Governor Kate Brown in 2017, Executive Order 17-20 targets state agencies to improve energy efficiency. Section 5(b) emphasizes a prioritization of energy efficiency in affordable housing to reduce utility bills (Oregon 2017). In response to this directive, the Oregon Housing and Community Service Department partnered with the DOE and the Public Utility Commission to develop an assessment to identify the energy burden of Oregon's low-income population and also prioritize energy efficiency. The interagency assessment concluded that energy costs for low-income Oregonians are nearly $350 million per year, and it identified more than $113 million annual potential energy cost savings that can be achieved through low-income energy efficiency programs across the state (OR DOE, OR PUC, and OHCS 2019). The order identifies a number of strategies to achieve these cost savings, such as adopting energy codes for new buildings and including retrofit measures, such as smart thermostats and replacing electric resistance heating.

Pennsylvania Energy Affordability Study. In 2019, the Pennsylvania Public Utility Commission (PA PUC) released a report that examined home energy affordability for the state's low-income customers (Pennsylvania PUC 2019a). The report's goal was to determine what constitutes an affordable energy burden for low-income households in the state, which would advise changes to the bill payment assistance programs to achieve these affordable energy burden levels. In 2020, the PA PUC set a new policy to direct the state's regulated utilities to ensure that low-income customers spend no more than 10% of their income on energy bills and that the lowest-income customers spend no more than 6% of their income on energy bills (Pennsylvania PUC 2019b).

Washington Clean Energy Transformation Act. In 2019, Governor Jay Inslee passed the Clean Energy Transformation Act (CETA), which sets specific goals to achieve 100% clean electricity across Washington by 2045. Under CETA, the Washington Department of Commerce will assess the energy burdens of low-income households and the energy assistance offered by electric utilities. The department will consult with local advocates of vulnerable populations and low-income households to improve energy assistance programs. The department will publish a statewide summary to include the estimated level of energy burden and energy assistance among electric customers, identify drivers of energy burden and energy efficiency potential, and assess the effectiveness of current utility programs and mechanisms to reduce energy burdens (Washington State Department of Commerce 2020).

public health strategies and priorities despite their wide-reaching health implications.

IDENTIFY HIGHLY BURDENED GROUPS FOR PROGRAMS TO SERVE

Overburdened households, especially Black, Native American, Hispanic, and other communities of color, often are either marginalized and overlooked by utilities' energy efficiency program marketing or face additional barriers to program participation, such as high cost or financing barriers (Leventis, Kramer, and Schwartz 2017). Creating targeted energy efficiency marketing beyond direct billing mailers can drive positive outcomes for the whole system.

Policymakers can also look beyond energy burden as an indicator to identify highly burdened groups, taking into account factors such as income, unemployment rates, race and ethnicity, geography, education, and multiple other stressors—including air pollution and health indicators. By using metrics beyond energy burden, policymakers and program implementers can better invest resources in communities that experience the highest levels of marginalization underinvestment, and negative social and health impacts (Lin et al. 2019). Policymakers can design and implement programs that meet the needs of highly burdened groups through robust community engagement. For example, local governments can design programs to improve access to affordable, energy-efficient housing by mandating or incentivizing stringent energy efficiency standards, streamlining permit and inspection processes, and amending zoning codes for construction of more housing units, while also using neighborhood approaches to involve and empower community members in these processes (Samarripas and de Campos Lopes 2020).

TEXT BOX 3. MEETING THE NEEDS OF HIGHLY BURDENED GROUPS: CASE STUDIES

Minneapolis Green Zones: The Minneapolis Climate Action Plan's Environmental Justice Working Group developed the idea of *Green Zones*, a place-based policy initiative aimed at improving health and supporting economic development. The city used data to identify two such zones—a Northern Green Zone and a Southern Green Zone—where residents face disproportionate burdens across areas such as equity, displacement, air quality, brownfields and soil contamination, housing, green jobs, food access, and greening (City of Minneapolis 2020). Once created, the city designed programs to direct investment into these communities. The Green Zones provide an example of how policymakers can work to identify highly burdened communities and create programs that meet the needs of residents in these areas.

Energy Burden as a Program Qualification: Efficiency Vermont. Efficiency Vermont (EVT), the energy efficiency program implementer for the state's utility-funded energy efficiency programs, conducted a 2018 study of equity measurements to better understand how the clean energy industry defines, collects, analyzes, and reports data on equity. This study informed changes to the design of EVT's Targeted High Use Program, which launched in 2011 and originally qualified customers based on two factors: income (< 80% of Area Median Income [AMI]) and a minimum energy use of 10,000 kWh/year. The program historically served approximately 350 households per year, working with the DOE's Weatherization Assistance Program (WAP) to conduct energy assessments and then install LEDs and water-saving measures, identify appliances for replacement, and replace high-efficiency heat pumps and heat pump water heaters where appropriate. Through its equity analysis, EVT determined that the energy use threshold was too high and excluded many customers with high energy burdens—but lower energy use—from accessing the program. In 2019, EVT changed the program qualification to two factors: income (< 80% AMI) and electric energy burden (≥ 3%). This change allowed it to recenter the program around energy burden reduction by qualifying not only more customers but also those who have high energy burdens yet may have previously been disqualified based on their energy use.

Efforts to alleviate high energy burdens should aim not only to identify those with high burdens and energy use but also to understand who has been overlooked by past efforts and develop strategies to address the needs of these households. Text box 3 contains additional case studies of city- and utility-led strategies to meet the needs of their overburdened communities.

Accelerate Investment in Low-Income Housing Retrofits, Energy Efficiency, and Weatherization

The current need for low-income energy efficiency and weatherization far exceeds allocated resources. In 2017, utility-led energy efficiency administrators allocated only 5% of electric and 22% of natural gas energy efficiency expenditures to low-income programs (CEE 2019). This funding allocation shows that energy efficiency funds are not currently distributed to ensure that low-income households have equitable access to these investments and their benefits.

Policymakers and advocates can work toward leveraging and allocating additional funding for low-income energy efficiency and weatherization programs. They can also help ensure that these programs follow best practices to increase their impact. Following are several useful strategies for ramping up additional funding for low-income energy efficiency and weatherization.

INCREASE FEDERAL FUNDING FOR LIHEAP AND WAP

Although an estimated 36 million U.S. households are currently eligible for weatherization, the DOE's Weatherization Assistance Program (WAP) has served only 7 million households over the past 40 years (Bullen 2018; DOE 2016). WAP serves about 100,000 homes per year through DOE and leveraged funds, which is far fewer than both the eligible households nationally and the 15.7 million severely energy burdened households estimated in this study (NASCSP 2020b). At the current rate, it would take 360 years to weatherize all eligible households through WAP—assuming no more households become WAP-eligible over time.

Congress funds WAP and allows funds to be transferred to the program from the Department of Health and Human Services' Low-Income Home Energy Assistance Program (LIHEAP). WAP can also utilize additional leveraged funds. States can transfer 15% (or up to 25% with a waiver) of LIHEAP bill assistance funds to WAP to supplement DOE weatherization funding. Over the past 10 years, annual expenditures directed toward weatherization have ranged from $1 billion to $3 billion per year, with the American Recovery and Reinvestment Act greatly increasing low-income funding for WAP (Brown et al. 2019). The National Association for State Community Services Programs' 2018 funding report estimates that WAP grantees had access to $1.1 billion in total available funding in 2018, with $247 million direct base funding from the DOE, $453 million from LIHEAP-transferred funding, and $408 million from utilities, state-sourced revenue, and other sources (NASCSP 2020b). Non-DOE WAP funds in 2018 added an additional $861 million, or $3.48 for every DOE-invested dollar (NASCSP 2020b).

The federal government has the ability to increase both WAP and LIHEAP budgets to better meet households' needs. From 2008 to 2018, DOE base funding for WAP has fluctuated from a high of $450 million in 2009 to a low of $68 million in 2012 (DOE 2009, 2012). In 2020, Congress allocated $305 million to WAP—a 23% increase ($58 million) compared to the funds allocated in 2018 (DOE 2020). Even so, leveraging additional state, local, and other funding helps supplement and increase available weatherization funds. In addition, states can decide to increase the LIHEAP percentage they transfer to WAP to better support the program. Further, it is essential that the increased demand for adequate cooling systems be assessed in the allocation of WAP and LIHEAP funds. For households across the South, rising temperatures and the increasing frequency and duration of heat waves are likely to increase cooling needs—and thus energy expenses (Berardelli 2019).

The COVID-19 pandemic has added to the urgency of increasing support for low-income bill payment assistance. On May 8, 2020, the federal government authorized $900 million in supplemental LIHEAP funding to help "prevent, prepare for, or respond to" home energy needs surrounding the national emergency created by COVID-19 (HHS 2020). On May 15, 2020, the U.S. House of Representatives passed the Health and Economic Recovery Omnibus Emergency Solutions (HEROES) Act, which would add an additional $1.5 billion for LIHEAP to address energy access and security issues resulting from the COVID-19 pandemic (116th Congress 2020). As of publication, the Senate has not passed this legislation.

INCREASE STATE, LOCAL, AND UTILITY FUNDING FOR ENERGY EFFICIENCY AND WEATHERIZATION

Funding from states, local governments, and utilities can also support low-income energy efficiency and weatherization efforts. In many states, PUCs can set low-income energy efficiency spending and/or savings requirements—as well as energy burden reduction targets—for their regulated utilities. As of 2017, of the 27 states with electric and/or natural gas Energy Efficiency Resource Standards (EERS), 18 had low-income energy efficiency spending requirements in place (Berg and Drehobl 2018; Gilleo 2019). States and local governments can also fund and implement their own energy efficiency and weatherization programs separately from WAP or as a WAP add-on. They can, for example, allocate funds—such as from Community Development Block Grants (CDGB)—to joint or independent energy efficiency and weatherization programs.

Policy approaches can be aligned to leverage funding resources and maximize benefits for residents, including reduced energy burdens and safer and healthier housing.

Appendix C and text box 4 include examples of cities and states that created independent energy efficiency and weatherization programs to address high energy burdens.

INTEGRATE ENERGY, HEALTH, AND HOUSING FUNDING AND RESOURCES.

High energy burdens, housing, and health are inextricably linked. In our study, many of the groups who experience high energy burdens also live in inadequate housing and disproportionally suffer from a variety of other harms, including higher than average exposures to environmental pollution (Tessum et al. 2019) and higher than average rates of certain preventable illnesses and diseases (CDC 2013). Although the recent COVID-19 pandemic has sharply illustrated this disparity, the same story plays out across a variety of preventable harms.[19] Policy approaches can be aligned to leverage funding resources and maximize benefits for residents, including reduced energy burdens and safer and healthier housing.

The benefits of these programs can be much greater when the goals of saving energy and protecting health are sought in tandem. Typical energy efficiency and weatherization services can provide a range of health benefits. Poorly sealed building envelopes allow pests, moisture, and air pollution to infiltrate (Institute of Medicine 2011), which can harm respiratory health through pest allergies, mold growth, and lung disease. Leaky windows, faulty HVAC systems, and poor insulation can lead to cold drafts and extreme home temperatures during summer and winter months. This can trigger heat-related illnesses and asthma attacks, as well as exacerbate other respiratory illnesses (AAFA 2017; American Lung Association 2020; CDC 2016). Addressing these issues through energy efficiency and weatherization will result in improved health outcomes; it will also reduce household energy burdens.

[19] For more on the disparities among COVID-19 fatalities, see Malcolm and Sawani (2020); Hooper, Nápoles, and Pérez-Stable (2020); and CDC (2020).

TEXT BOX 4. CITY- AND STATE-FUNDED ENERGY AFFORDABILITY PILOT PROGRAMS

Philadelphia: To meet its energy burden goals, Philadelphia has partnered on multiple pilot programs to reduce high energy burdens for low-income single and multifamily households. In 2017, the Philadelphia Energy Authority (PEA) launched its Multifamily Affordable Housing Pilot program in partnership with public and private-sector groups, including the local electric and natural gas utilities, property owners, energy service companies, program implementers, contractors, and technology providers (PEA 2020a). The program's goal was to deliver deep energy savings of more than 30% to low-income multifamily building residents in the city. In 2018, PEA and partners completed the program's first phase, which included low-cost measures and measures to collect energy data. These data were then used in the second phase to design deeper savings measures, such as HVAC and building envelope measures.

In response to COVID-19, PEA is developing a platform with its partners and advocates to coordinate and streamline low-income homeowner services aimed at improving home safety, health, affordability, and comfort (PEA 2020b). Set to launch in 2021, PEA's Built to Last pilot program aims to deliver comprehensive home improvements that will reduce energy burden while improving health and safety. The program will serve 80–100 homes and will streamline benefit screening, property assessment, and construction management. To cover program costs, Built to Last aims to combine available funding with grants and microfinancing options. PEA plans to deploy the Built to Last program at a larger scale in 2022 (PEA 2020b).

Pittsburgh. The city recognized that while Pittsburgh residents have some of the lowest utility rates in the country, they still pay almost twice the national average for their energy bills, leading to high energy burdens. Over the course of a few years, Pittsburgh developed a Climate Action Plan and launched both its resilience strategy (OnePGH) and its equality indicator project. These three projects helped the city identify residential energy burden as one of the primary challenges that local communities face (City of Pittsburgh 2019). As part of the Bloomberg Mayor's Challenge, Pittsburgh created Switch PGH to address high energy burdens through a civic engagement tool that gamifies home improvement (Mayors Challenge 2018). Switch PGH helps residents make lasting energy efficiency behavior changes and incentivizes home upgrades to reduce energy burdens.

Colorado. The Colorado State Energy Office awarded GRID Alternatives, a solar installer that focuses on the low-income market, a $1.2 million grant to launch a demonstration project with the goal of reducing the energy burden for more than 300 low-income households. The program also aimed to improve understanding of how to make community solar programs with low-income participants mutually beneficial for both utilities and participants (Cook and Shah 2018) Through this program, households saved from 15% to more than 50% on their utility bills, with an average annual savings of $382.

Myriad programs exist to address health and safety issues within homes, as well as to preserve and grow the affordable housing stock. Opportunities exist to integrate these programs and resources to more comprehensively address the energy, health, and housing needs of the households most in need of assistance.[20] For example, many homes must defer energy efficiency investments due to a home's physical issues, such as those related to structural deficiencies, moisture, and/or mold. According to Rose et al. (2015), WAP agencies estimated that such issues led to a 1–5% deferral rate for WAP income-eligible homes. In some areas, however, the problem is worse. In western Wisconsin, for example, a Community Action Agency and WAP provider serving four counties reported a deferral rate approaching 60% (NASCSP 2020a). Addressing nonenergy-related housing issues would allow more homes to be weatherization-ready.

Integrating programs creates opportunities to streamline administration and reduce operating redundancies that can leave more funding for energy efficiency and weatherization measures that enable households to save on energy costs. Pooling resources and establishing cross-sector referral networks not only stretches program budgets, but it also can make programs more accessible for residents by streamlining eligibility and enrollment processes. For instance, offering a single contact point or a streamlined process can give participants a variety of services simultaneously to meet their energy, health, and housing needs (Levin, Curry, and Capps 2019). This can help mitigate barriers that arise when people have to navigate multiple separate services with varying eligibility requirements and enrollment processes. Efficiency Vermont's Healthy Homes Initiative (HHI) is one such example. A partnership between the state's WAP partners and community-based organizations that offer health interventions, HHI is coordinated through Vermont's Office of Economic Opportunity. Using

[20] ACEEE recently published several reports exploring the intersection of health and energy, including *Protecting the Health of Vulnerable Populations with In-Home Energy Efficiency: A Survey of Methods for Demonstrating Health Outcomes* (www.aceee.org/research-report/h1901); *Making Health Count: Monetizing the Health Benefits of In-Home Services Delivered by Energy Efficiency Programs* (www.aceee.org/research-report/h2001); and *Braiding Energy and Health Funding for In-Home Programs: Federal Funding Opportunities* (www.aceee.org/research-report/h2002).

One Touch, an electronic platform for healthy home resources, HHI has established a robust referral network and successfully integrated healthy home principles into its residential energy efficiency program design.

The health sector is also beginning to realize the efficiencies of combining health and energy assessments and interventions (Hayes and Gerbode 2020). For example, a single contractor could be trained to both identify and address a family's asthma triggers, energy efficiency needs, and fall risks, thereby reducing the associated logistical burden on residents who might otherwise have to coordinate each service individually. Efforts such as this are beginning to appear across the country. In 2015, the state of Washington directed more than $4 million in competitive grants to fund collaborations among clinical practitioners, home retrofitters, and community service organizations as a means of empowering clinicians and others to refer participants for a range of coordinated services (e.g., comprehensive in-home repairs and community health worker visits) (Levin, Curry, and Capps 2019). In New York, the State Energy Research and Development Authority (NYSERDA) recently kicked off a value-based payment pilot program that seeks to implement a healthy homes approach; through this program, Medicaid managed care organizations will partly cover residential upgrades when healthcare cost savings and benefits to residents are verified (NYSERDA 2018). Such cross-sectoral approaches to energy efficiency and weatherization seek to address some of the major root causes of health and energy inequities while making enrollment and participation feasible and accessible for residents. The benefits of energy efficiency cut across the health and energy sectors; by working to integrate resources, policymakers can maximize these benefits.

Housing policy can also help ensure that energy efficiency is integrated into efforts to upgrade and expand the affordable housing stock. State and local governments can play a key role in these integrating approaches. For example, a growing number of state housing finance agencies (HFAs)—state-chartered entities responsible for ensuring affordable housing across states—have included energy efficiency requirements in their allocation criteria for low-cost financing programs such as federal Low-Income Housing Tax Credits and grant programs administered to local governments. The same is true for local housing authorities, which increasingly incorporate energy efficiency into the maintenance and repair of their subsidized housing stock (EPA 2018). Text box 5 offers a brief case study of how one local government systematically required energy efficiency in its rental certification process, ensuring that all types of rental housing meet a specific level of energy performance.

ENABLE ACCESSIBLE AND FAIR FINANCING OPTIONS

Many low-income households face barriers—such as credit eligibility—to investing in energy efficiency; these barriers can prevent them from participating in energy efficiency programs or installing energy efficiency upgrades that require financing for up-front costs. With the right consumer protections in place, financing can enable households to undertake cost-effective energy efficiency investments to lower their energy usage and bills. Local and state governments, utilities, private lenders, and nonprofit or community-based organizations can act to create and/or enable low- or no-cost financing options (i.e., payments are offset by energy cost savings) for energy efficiency investments.

Several types of financing instruments, such as on-bill payment (i.e., loan repayments included on the utility bill) and energy service agreements are becoming more common (Leventis, Kramer, and Schwartz 2017). Similarly, opportunities such as Commercial Property Assessed Clean Energy (C-PACE) can increase energy efficiency financing in the affordable multifamily sector. SEE Action's 2017 report, *Energy Efficiency Financing for Low- and Moderate-Income Households,* provides a comprehensive overview of the pros and cons of various financing options for both single and multifamily low-income households (Leventis, Kramer, and Schwartz 2017).

Improve program design, delivery, and evaluation through best practices and community engagement

Program designers and implementers can collaborate and effectively engage with a community to create programs that fit its specific needs rather trying to fit the community into an existing program design. They can also incorporate best practices into their program design, delivery, and evaluation, and can emulate successful peer program models to increase program effectiveness and impact.

CONDUCT COLLABORATIVE AND EFFECTIVE COMMUNITY ENGAGEMENT

To create programs that effectively reduce high energy burdens, energy efficiency and renewable energy program designers and implementers can work to engage and include local stakeholders throughout the program planning and implementation processes.

By connecting with, listening to, and partnering with community-serving organizations and community members in highly impacted communities, program

TEXT BOX 5. THE CITY OF BOULDER'S SMARTREGS PROGRAM

In 2010, the city council in Boulder, Colorado, adopted SmartRegs, a program that requires all rental housing units in the city to demonstrate that their efficiency approximates or exceeds the standards set by the 1999 Energy Code. The program was integrated into the city's existing rental license program, which requires a rental property to obtain and renew its rental license every four years. This renewal entails an inspection for health and safety measures, and SmartRegs added energy efficiency requirements that must be met to certify that the property is approved for rental. All single- and multifamily units that offer long-term licensed rental housing are subject to the requirement. For larger multifamily buildings, a sample of representative apartments can be inspected.

Boulder also offers a companion EnergySmart program that provides technical assistance, help with selecting contractors for energy efficiency improvements, and financial incentives beyond those offered by the local utility. EnergySmart is funded primarily by Boulder County and provides services to all municipalities in the county.

SmartRegs has been recognized not only for saving energy and related costs but also for leading to widescale upgrades in the city's rental housing stock. Over the course of the eight-year compliance timeline, nearly all of the approximately 23,000 licensed rental units have become compliant (City of Boulder 2020a). The most common upgrades were attic, crawlspace, and wall insulation. The average upgrade cost has been about $3,000 per unit, of which an average of $579 was paid by city- and utility-sponsored rebates. As of 2018, the city estimates that the program has saved about 1.9 million kWh of electricity, 460,000 therms of natural gas, $520,000 in energy costs, and 3,900 million metric tons of carbon dioxide. The city estimates the total investment in the program at just over $8 million, including nearly $1 million in rebates (City of Boulder 2020b).

administrators can identify the best measures, financing options, delivery methods, and marketing strategies to help residents reduce high energy burdens and meet their needs. Achieving this connection requires partnering with the community on program design and identifying and addressing barriers to participation for key stakeholders. This often requires engagement and trust-building over a long time period.

Robust community engagement incorporates the voices of and/or delegates power to community members. Such engagement can help develop neighborhood-centered programs that are most successful when combined with consistent funding, quality delivery infrastructure, and targeted outreach and engagement (USDN 2019). For more information on best practices in stakeholder engagement, see the DOE's Clean Energy for Low-Income Communities (CELICA) Online Toolkit at betterbuildingssolutioncenter.energy.gov/CELICA-Toolkit/stakeholder-engagement.

To include residents with high energy burdens in policy and program design, cities, states, and utilities can establish working groups, task forces, committees, and other structures that give residents a formal decision-making role. Creating this engagement when energy insecurity strategies, goals, and/or programs are first being developed allows for more input and direction from community members. Local energy planning efforts can also start with a community needs assessment led by a formal body of community residents. Local government and community leaders can then use this assessment's findings to drive local energy affordability policies and program developments based on the findings' prioritized needs and strategies.

Policymakers and program implementers can minimize stakeholder and community participation barriers by funding or compensating participants for their time and participation in stakeholder engagement processes. For example, offering stipends to compensate participants for their time and expertise, setting realistic time expectations, creating accessible logistics, and offering additional incentives can increase participation and access (Curti, Andersen, and Write 2018). Other incentives to reduce engagement barriers include childcare, meals, and transit passes.

Policymakers can also move to a model of *energy democracy* in which community residents are innovators, planners, and decision makers on how to use and create energy in a way that is local, renewable, affordable, and just (Fairchild and Weinrub 2017). Communities that have transitioned to an energy democracy have shifted away from "an extractive economy, energy, and governance system to one that is regenerative, provides reparations, transforms power structures, and creates new governance and ownership practices (ECC 2019)." The Emerald Cities Collaborative led the creation of an *Energy Democracy Scorecard*, which provides a framework for communities to move toward an energy democracy. Policymakers can work to create energy democracy frameworks in their communities by working with community members to recognize power imbalances and create dialogues about systemic barriers that must be addressed in order to correct long-standing injustices and inequalities in the energy and related sectors. This can help move the energy planning model to one of community self-determination and shared ownership. For more information, see emeraldcities.org/about/energy-democracy-scorecard.

ENCOURAGE BEST PRACTICES FOR PROGRAM DESIGN, DELIVERY, AND EVALUATION TO MAXIMIZE BENEFITS IN LOW-INCOME COMMUNITIES

Researchers from ACEEE and other organizations have established numerous best practice strategies and case studies of ways to improve and expand low-income energy efficiency programs and investments (Aznar et al. 2019; Nowak, Kushler, and Witte 2019; EDF 2018; Gilleo, Nowak, and Drehobl 2017; Samarripas and York 2019; Cluett, Amann, and Ou 2016; Ross, Jarrett, and York 2016; Reames 2016).

Table 5 includes low-income program best practices across five categories: coordination, collaboration, and segmentation; funding and financing; measures, messaging, and targeting; evaluation and quality control; and renewables and workforce development. **Appendix D** offers more detailed descriptions and examples of each of these best practices.

TABLE 5. Low-income program best practices by category

Coordination, collaboration, and segmentation	Funding and financing	Measures, messaging, and targeting	Evaluation and quality control	Renewables and workforce development
Community engagement and participatory planning	Leverage diverse funding sources	Include health and safety measures and healthier building materials	Collect and share metrics	Integrate energy efficiency and solar
Statewide coordination models	Inclusive financing models	Prioritize deep energy-saving measures	Conduct robust research and evaluation	Support the development of a diverse and strong energy efficiency workforce
One-stop-shop program models	Align utility and housing finance programs	Integrate direct-installation and rebate programs	Include quality control	
Market segmentation		Target high energy users and vulnerable households	Incorporate nonenergy benefits	
Fuel neutral programs		Incorporate new and emerging technologies in low-income programs		
		Effectively message programs in ways that provide clear value and actionable guidance		

Conclusions and Further Research

High energy burdens and energy insecurity are well-documented and pervasive national issues. Even in 2017, a time of economic prosperity, well over one-quarter of all U.S. households experienced a high energy burden. As this indicates, we need a renewed focus on equitable clean energy development and just energy transitions to ensure that investments in energy efficiency and renewable energy address energy insecurity. Climate change also underscores the urgency in addressing high household energy burdens. As temperatures continue to rise and heat waves become more common, access to clean, affordable energy is needed more than ever. We need cross-sectoral approaches that address the intersection of energy, health, and housing in the face of climate change.

Both nationally and in metro areas, this study finds that certain groups pay disproportionally more of their income on energy costs, including low-income households, communities of color, older adults, renters, and those residing in older buildings. Even though each metro area has a unique energy burden landscape, all cities have energy security inequities and can work to address them through collaborative policy and program decisions. Policymakers at the local, state, and utility levels can direct energy efficiency and renewable energy investments to disadvantaged and historically underinvested communities. They can then measure and ensure that these investments provide equitable benefits to local jobs, community health, and residential energy affordability.

Energy burdens are not the sole indicator of energy insecure households but rather provide one metric for determining energy insecurity. Further research is needed to identify the main physical drivers of high energy burdens, as well as the policies best suited to address the needs of the most highly energy burdened households. To better understand their communities' energy insecurity landscape, cities and states—and their energy, health, and housing agencies—as well as utilities are well-positioned to conduct detailed energy burden analyses, including qualitative data collection and interviews. Such studies would enable a first step toward setting more targeted energy affordability and energy burden goals and creating equitable, cross-sectoral policies and programs for achieving greater access to affordable energy for all.

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APPENDIX A.
Energy Burden Data

Appendix A.1—National Energy Burden Data

A1. National energy burden data including sample sizes, median energy burdens, median income, median monthly energy bills, and the percentage of households in each group with a high and severe burden

Subgroups	Sample size	Median energy burden	Median annual income	Median annual energy expenditures	High burden percentage (>6%)	Severe burden percentage (>10%)
All households	53,539	3.1%	$58,000	$1,800	25%	13%
Low-income (≤ 200% FPL)	16,685	8.1%	$18,000	$1,464	67%	40%
Low-income with adult over 65	6,018	9.3%	$15,000	$1,440	74%	47%
Low-income with child under six	2,665	7.1%	$26,400	$1,800	59%	33%
Low-income with disability	5,759	8.7%	$14,660	$1,344	69%	43%
Non-low-income (> 200% FPL)	36,854	2.3%	$84,005	$2,040	6%	1%
White (non-Hispanic)	33,219	2.9%	$65,000	$1,920	23%	11%
Black	7,747	4.2%	$36,000	$1,560	36%	21%
Hispanic	8,435	3.5%	$47,400	$1,680	28%	14%
Native American	1,003	4.2%	$40,000	$1,680	36%	19%
Older adults (65+ years)	15,750	4.2%	$40,015	$1,800	36%	19%
Renters	20,455	3.4%	$36,000	$1,320	30%	17%
Owners	33,082	3.0%	$75,000	$2,160	22%	11%
Single family	37,423	3.1%	$70,020	$2,160	24%	12%
Multifamily (5+ units)	9,936	2.4%	$35,450	$960	22%	12%
Low-income multifamily (5 + units, ≤ 200% FPL)	4,563	5.6%	$14,300	$960	47%	26%
Small multifamily (2–4 units)	3,708	3.4%	$34,700	$1,200	29%	17%
Manufactured homes	2,440	5.3%	$34,800	$1,800	45%	25%
Buildings built before 1980	28,013	3.4%	$50,040	$1,800	29%	15%
Buildings built after 1980	25,525	2.8%	$66,000	$1,920	21%	11%

Appendix A.2–Regional Energy Burden Data

A2.1. Regional energy burdens, including sample sizes for each region, median energy burdens, median monthly energy bill, and the percentage with high and severe burdens

Region	Sample size	Median energy burden	Median annual income	Median annual energy expenditures	Upper-quartile energy burden	High burden percentage (>6%)	Severe burden percentage (>10%)
East North Central	7,422	3.6%	$52,500	$1,920	6.8%	29%	15%
East South Central	2,177	4.4%	$39,400	$1,800	8.5%	38%	21%
Middle Atlantic	4,851	3.4%	$60,000	$2,040	6.8%	29%	16%
Mountain	3,932	2.9%	$57,625	$1,680	5.2%	21%	11%
New England	2,778	3.5%	$71,985	$2,640	6.7%	29%	15%
Pacific	11,177	2.3%	$69,800	$1,680	4.5%	18%	9%
South Atlantic	11,363	3.2%	$56,120	$1,920	6.2%	26%	14%
West North Central	2,412	3.1%	$55,100	$1,800	5.8%	25%	12%
West South Central	7,427	3.3%	$52,000	$1,800	6.0%	25%	13%
National	53,539	3.1%	$58,000	$1,800	6.0%	25%	13%

A2.2. Regional median energy burdens for income-based groups

Region	Low-income (≤200% FPL)	Low-income with older adults (65+)	Low-income with child under 6	Low-income with disability	Low-income multifamily (5+ units, ≤200% FPL)	Non-low-income (>200% FPL)
East North Central	9.1%	9.8%	8.2%	9.2%	6.0%	2.6%
East South Central	9.1%	10.0%	8.6%	9.9%	6.6%	2.9%
Middle Atlantic	9.4%	10.7%	7.9%	10.2%	6.9%	2.6%
Mountain	6.9%	8.4%	5.7%	7.7%	4.5%	2.2%
New England	10.5%	11.6%	9.6%	10.8%	5.6%	2.9%
Pacific	6.8%	7.5%	5.4%	6.9%	5.3%	1.7%
South Atlantic	8.4%	9.5%	7.7%	8.8%	5.8%	2.3%
West North Central	7.9%	9.1%	7.1%	7.9%	4.7%	2.5%
West South Central	7.7%	9.6%	6.6%	9.0%	5.8%	2.4%
National	8.1%	9.3%	7.1%	8.7%	5.6%	2.3%

A2.3. Regional median energy burdens based on race/ethnicity, age, and tenure status

Region	White (non-Hispanic)	Black	Hispanic	Older adults (65+ years)	Renter	Owner
East North Central	3.4%	5.1%	3.4%	4.7%	4.2%	3.3%
East South Central	4.0%	6.2%	5.0%	5.7%	5.3%	4.0%
Middle Atlantic	3.2%	4.4%	4.5%	4.8%	3.8%	3.2%
Mountain	2.6%	3.3%	3.7%	3.8%	3.0%	2.8%
New England	3.4%	4.0%	4.6%	4.8%	3.6%	3.5%
Pacific	2.1%	3.2%	3.0%	3.3%	2.5%	2.2%
South Atlantic	2.9%	4.0%	3.4%	4.4%	3.5%	3.0%
West North Central	3.0%	4.6%	3.3%	3.9%	3.9%	2.9%
West South Central	2.9%	4.0%	4.0%	4.4%	3.6%	3.1%
National	2.9%	4.2%	3.5%	4.2%	3.4%	3.0%

A2.4. Regional median energy burdens based on building type

Region	Single family	Multifamily (5+ units)	Low-income multifamily (5+ units, ≤200% FPL)	Built before 1980	Built after 1980
East North Central	3.6%	3.0%	6.0%	4.0%	2.9%
East South Central	4.3%	3.9%	6.6%	4.9%	3.9%
Middle Atlantic	3.5%	2.5%	6.9%	3.6%	2.9%
Mountain	2.9%	2.3%	4.5%	3.3%	2.7%
New England	3.6%	2.4%	5.6%	3.7%	3.1%
Pacific	2.4%	1.9%	5.3%	2.3%	2.3%
South Atlantic	3.2%	2.5%	5.8%	3.6%	2.9%
West North Central	3.1%	2.6%	4.7%	3.4%	2.7%
West South Central	3.3%	2.6%	5.8%	3.9%	3.0%
National	3.1%	2.4%	5.6%	3.4%	2.8%

A2.5. Regional upper-quartile energy burdens for income-based groups (25% of households in each group have a burden above the upper-quartile threshold)

Region	Low-income (≤200% FPL)	Low-income with older adults (65+)	Low-income with child under 6	Low-income with disability	Low-income multifamily	Non-low-income (>200% FPL)
East North Central	16.4%	17.6%	14.2%	15.9%	10.6%	3.9%
East South Central	15.7%	15.7%	18.7%	17.2%	12.0%	4.2%
Middle Atlantic	17.6%	20.1%	15.6%	18.5%	12.9%	4.0%
Mountain	12.0%	15.3%	9.6%	13.6%	8.4%	3.3%
New England	19.3%	21.7%	15.4%	19.2%	10.8%	4.5%
Pacific	12.0%	13.7%	10.2%	12.0%	9.2%	2.8%
South Atlantic	14.7%	15.9%	12.4%	15.7%	10.0%	3.6%
West North Central	14.1%	14.5%	13.7%	14.6%	8.7%	3.6%
West South Central	12.9%	17.5%	10.1%	16.5%	10.2%	3.5%
National	14.4%	16.3%	12.0%	15.6%	10.1%	3.6%

A2.6. Regional upper-quartile energy burdens based on race/ethnicity, age, and tenure status (25% of households in each group have a burden above the upper-quartile threshold)

Region	White (non-Hispanic)	Black	Hispanic	Older adults (65+ years)	Renter	Owner
East North Central	6.4%	10.0%	6.1%	8.4%	8.4%	6.1%
East South Central	7.4%	12.3%	9.2%	10.3%	10.9%	7.2%
Middle Atlantic	6.2%	9.8%	8.6%	9.3%	8.0%	6.1%
Mountain	4.8%	6.3%	6.2%	7.0%	5.7%	4.9%
New England	6.3%	8.1%	9.3%	9.5%	7.8%	6.0%
Pacific	4.1%	6.5%	5.6%	6.4%	5.1%	4.1%
South Atlantic	5.5%	8.0%	6.2%	8.4%	7.4%	5.5%
West North Central	5.5%	9.3%	6.1%	7.3%	7.8%	5.2%
West South Central	5.1%	7.6%	7.1%	8.6%	7.3%	5.4%
National	5.5%	8.4%	6.5%	8.1%	7.1%	5.4%

A2.7. Regional upper-quartile energy burdens based on building type (25% of households in each group have a burden above the upper-quartile threshold)

Region	Single family	Multifamily (5+ units)	Low-income multifamily (≤200% FPL, 5+ units)	Built before 1980	Built after 1980
East North Central	6.6%	6.5%	10.6%	7.4%	5.7%
East South Central	7.8%	8.2%	12.0%	9.6%	7.5%
Middle Atlantic	6.7%	6.5%	12.9%	7.0%	5.9%
Mountain	5.0%	4.7%	8.4%	5.9%	4.8%
New England	6.4%	6.1%	10.8%	7.2%	5.6%
Pacific	4.4%	4.3%	9.2%	4.7%	4.3%
South Atlantic	6.0%	5.3%	10.0%	7.2%	5.5%
West North Central	5.7%	5.5%	8.7%	6.4%	5.1%
West South Central	5.9%	5.4%	10.2%	7.4%	5.2%
National	5.8%	5.3%	10.1%	6.7%	5.3%

Appendix A.3—Metro-Level Energy Burden Data

A3.1. Metro-level energy burdens, including sample sizes for each city, median energy burdens, median monthly energy bill, and percentage with high burden and severe burden

Metro area	Sample size	Median energy burden	Median annual income	Median annual energy expenditures	Upper-quartile energy burden	High burden percentage (>6%)	Severe burden percentage (>10%)
Atlanta	1,957	3.5%	$60,000	$2,280	6.5%	28%	14%
Baltimore	1,741	3.0%	$75,100	$2,280	5.5%	23%	11%
Birmingham	1,755	4.2%	$53,300	$2,280	7.4%	34%	18%
Boston	1,728	3.1%	$81,925	$2,640	5.8%	24%	12%
Chicago	1,788	2.7%	$65,350	$1,800	4.8%	20%	10%
Dallas	2,472	2.9%	$60,000	$1,920	4.9%	19%	8%
Detroit	1,917	3.8%	$57,000	$2,160	6.9%	30%	16%
Houston	2,164	3.0%	$60,000	$1,800	5.3%	21%	11%
Las Vegas	1,968	2.8%	$54,700	$1,560	4.8%	18%	10%
Los Angeles	2,351	2.2%	$61,900	$1,440	4.4%	17%	9%
Miami	1,978	3.0%	$48,050	$1,440	5.5%	23%	12%
Minneapolis	1,943	2.2%	$81,000	$1,920	3.6%	12%	5%
New York City	1,510	2.9%	$67,500	$1,920	6.0%	25%	15%
Oklahoma City	2,111	3.3%	$52,000	$1,800	5.8%	24%	11%
Philadelphia	1,852	3.2%	$66,500	$2,160	6.3%	26%	14%
Phoenix	2,000	3.0%	$60,000	$1,800	5.2%	21%	10%
Richmond	1,933	2.6%	$69,000	$1,920	4.7%	17%	9%
Riverside	2,070	3.6%	$58,750	$2,160	6.7%	29%	15%
Rochester	1,807	3.8%	$56,000	$2,160	6.7%	29%	15%
San Antonio	2,014	3.0%	$55,000	$1,800	5.4%	22%	11%
San Francisco	1,950	1.4%	$100,000	$1,440	2.9%	10%	6%
San Jose	2,043	1.5%	$109,000	$1,560	2.9%	11%	6%
Seattle	2,162	1.8%	$79,800	$1,440	3.3%	11%	6%
Tampa	1,701	2.8%	$52,000	$1,560	5.3%	21%	11%
Washington, DC	2,214	2.0%	$100,000	$2,160	3.9%	14%	7%
National	53,539	3.1%	$58,000	$1,800	6.0%	25%	13%

A3.2. Metro-level median energy burdens for income-based groups

Metro area	Low-income (≤200% FPL)	Low-income with older adults (65+)	Low-income with child under 6	Low-income with disability	Low-income multifamily (5+ units, ≤200% FPL)	Non-low-income (>200% FPL)
Atlanta	9.7%	12.6%	8.1%	10.4%	6.6%	2.7%
Baltimore	10.5%	11.4%	7.8%	10.0%	7.5%	2.6%
Birmingham	10.9%	12.9%	9.3%	10.7%	6.8%	3.0%
Boston	10.1%	11.8%	9.5%	10.4%	6.6%	2.6%
Chicago	8.0%	9.5%	5.9%	8.0%	6.4%	2.1%
Dallas	6.7%	10.0%	6.0%	8.1%	5.0%	2.4%
Detroit	10.2%	12.0%	8.6%	10.7%	6.0%	2.8%
Houston	7.1%	9.9%	5.8%	9.6%	5.8%	2.2%
Las Vegas	6.5%	8.3%	5.0%	6.5%	5.3%	2.2%
Los Angeles	6.0%	6.4%	4.9%	6.1%	4.8%	1.6%
Miami	6.9%	8.0%	5.0%	7.6%	5.5%	2.1%
Minneapolis	6.6%	8.7%	4.7%	7.0%	4.3%	2.0%
New York City	9.3%	11.4%	7.5%	11.0%	8.0%	2.1%
Oklahoma City	7.8%	9.5%	6.1%	8.7%	6.5%	2.6%
Philadelphia	9.5%	10.4%	8.1%	10.1%	6.5%	2.4%
Phoenix	7.0%	8.3%	5.6%	7.3%	4.6%	2.4%
Richmond	8.2%	10.3%	6.9%	8.4%	5.0%	2.3%
Riverside	8.7%	10.6%	6.7%	9.6%	6.1%	2.7%
Rochester	9.5%	10.1%	7.9%	9.4%	6.0%	2.9%
San Antonio	7.4%	9.5%	6.0%	8.6%	4.8%	2.4%
San Francisco	6.1%	7.0%	4.7%	6.6%	4.9%	1.2%
San Jose	6.5%	8.1%	4.4%	7.6%	4.7%	1.2%
Seattle	6.0%	6.8%	4.4%	6.0%	4.1%	1.6%
Tampa	7.2%	8.0%	5.6%	8.0%	4.9%	2.1%
Washington, DC	7.5%	9.3%	5.9%	8.3%	5.2%	1.8%
National	8.1%	9.3%	7.1%	8.7%	5.6%	2.3%

A3.3. Metro-level median energy burdens based on race/ethnicity, age, and tenure status

Metro area	White (non-Hispanic)	Black	Hispanic	Older adults (65+)	Renter	Owner
Atlanta	3.1%	4.1%	4.7%	5.1%	3.7%	3.4%
Baltimore	2.8%	3.8%	3.3%	4.1%	3.2%	2.9%
Birmingham	3.8%	5.6%	4.8%	5.8%	5.2%	3.9%
Boston	3.0%	3.7%	3.6%	4.4%	3.2%	3.0%
Chicago	2.4%	4.1%	3.0%	3.7%	3.1%	2.5%
Dallas	2.6%	3.3%	3.8%	3.8%	2.9%	3.0%
Detroit	3.5%	5.3%	4.5%	5.2%	4.6%	3.6%
Houston	2.5%	3.5%	3.4%	4.1%	3.3%	2.7%
Las Vegas	2.7%	3.2%	3.0%	3.4%	3.0%	2.7%
Los Angeles	1.8%	3.6%	2.6%	3.2%	2.4%	2.1%
Miami	2.5%	3.4%	3.1%	4.2%	3.1%	2.8%
Minneapolis	2.2%	2.6%	2.7%	3.0%	2.3%	2.2%
New York City	2.6%	3.6%	3.8%	4.2%	3.3%	2.7%
Oklahoma City	3.1%	3.9%	4.2%	4.0%	3.9%	3.1%
Philadelphia	2.9%	4.4%	5.2%	4.4%	3.9%	3.0%
Phoenix	2.8%	3.2%	3.6%	4.0%	2.8%	3.1%
Richmond	2.4%	3.4%	2.9%	3.5%	2.9%	2.6%
Riverside	3.4%	3.9%	3.7%	5.1%	4.0%	3.4%
Rochester	3.6%	5.1%	5.4%	4.8%	4.3%	3.6%
San Antonio	2.7%	3.1%	3.4%	4.1%	3.1%	3.0%
San Francisco	1.2%	2.4%	1.2%	2.4%	1.4%	1.4%
San Jose	1.4%	1.8%	1.9%	2.4%	1.5%	1.5%
Seattle	1.8%	2.3%	2.0%	2.4%	1.8%	1.8%
Tampa	2.6%	3.6%	3.5%	3.8%	2.8%	2.9%
Washington, DC	1.7%	2.9%	2.7%	2.9%	2.0%	2.0%
National	2.9%	4.2%	3.5%	4.2%	3.4%	3.0%

A3.4. Metro-level median energy burdens based on building type

Metro area	Single family	Multifamily (5+ units)	Low-income multifamily (5+ units, ≤200% FPL)	Built before 1980	Built after 1980
Atlanta	3.7%	2.5%	6.6%	4.5%	3.3%
Baltimore	3.2%	2.5%	7.5%	3.6%	2.4%
Birmingham	4.1%	3.5%	6.8%	5.1%	3.6%
Boston	3.1%	2.2%	6.6%	3.2%	2.6%
Chicago	2.6%	2.7%	6.4%	2.9%	2.2%
Dallas	3.1%	2.2%	5.0%	3.5%	2.7%
Detroit	3.8%	2.5%	6.0%	4.3%	3.0%
Houston	3.0%	2.5%	5.8%	3.4%	2.7%
Las Vegas	2.8%	2.4%	5.3%	3.6%	2.7%
Los Angeles	2.3%	2.1%	4.8%	2.3%	2.1%
Miami	2.9%	2.9%	5.5%	3.3%	2.6%
Minneapolis	2.3%	1.8%	4.3%	2.5%	2.0%
New York City	3.0%	2.4%	8.0%	3.0%	2.4%
Oklahoma City	3.2%	3.3%	6.5%	3.8%	2.9%
Philadelphia	3.3%	2.7%	6.5%	3.6%	2.5%
Phoenix	3.1%	2.1%	4.6%	3.6%	2.8%
Richmond	2.6%	2.1%	5.0%	3.1%	2.3%
Riverside	3.5%	3.9%	6.1%	4.3%	3.3%
Rochester	3.7%	3.2%	6.0%	4.0%	3.4%
San Antonio	3.0%	2.6%	4.8%	3.9%	2.7%
San Francisco	1.5%	1.3%	4.9%	1.4%	1.4%
San Jose	1.6%	1.2%	4.7%	1.6%	1.3%
Seattle	1.9%	1.5%	4.1%	2.0%	1.7%
Tampa	2.8%	2.2%	4.9%	3.3%	2.5%
Washington, DC	2.2%	1.4%	5.2%	2.3%	1.9%
National	3.1%	2.4%	5.6%	3.4%	2.8%

A3.5. Metro-level upper-quartile energy burdens for income-based groups (25% of households in each group have a burden above the upper-quartile threshold)

Metro area	Low-income (≤200% FPL)	Low-income with older adults (65+)	Low-income with child under 6	Low-income with disability	Low-income multifamily	Non-low-income (>200% FPL)
Atlanta	16.2%	19.1%	12.8%	17.9%	11.7%	4.1%
Baltimore	21.7%	34.0%	10.9%	27.1%	5.5%	3.8%
Birmingham	18.3%	20.0%	17.1%	17.7%	13.9%	4.6%
Boston	18.6%	21.8%	16.0%	21.4%	11.7%	4.2%
Chicago	15.1%	17.5%	11.2%	13.2%	12.7%	3.1%
Dallas	11.4%	17.1%	8.5%	15.4%	7.9%	3.6%
Detroit	18.8%	21.2%	13.6%	19.8%	9.6%	4.3%
Houston	12.2%	20.2%	9.0%	22.0%	9.8%	3.2%
Las Vegas	13.8%	21.8%	8.0%	13.7%	10.9%	3.2%
Los Angeles	10.4%	11.4%	8.4%	11.2%	8.7%	2.6%
Miami	11.2%	13.3%	10.0%	13.0%	10.0%	3.0%
Minneapolis	12.2%	14.8%	6.9%	12.6%	7.7%	2.9%
New York City	16.8%	21.8%	14.1%	18.6%	15.0%	3.4%
Oklahoma City	12.5%	14.0%	9.9%	12.4%	10.2%	3.7%
Philadelphia	19.1%	24.9%	14.7%	20.0%	12.1%	3.8%
Phoenix	11.9%	15.3%	9.2%	12.7%	7.3%	3.5%
Richmond	15.6%	22.0%	10.4%	19.2%	8.8%	3.3%
Riverside	15.0%	16.6%	10.7%	16.5%	9.9%	3.9%
Rochester	15.9%	20.0%	14.0%	14.7%	9.9%	4.3%
San Antonio	13.3%	16.6%	9.2%	16.2%	9.2%	3.5%
San Francisco	14.3%	14.3%	8.5%	14.4%	11.0%	2.0%
San Jose	12.5%	14.9%	7.6%	14.9%	8.9%	2.0%
Seattle	10.9%	12.0%	9.2%	9.9%	6.8%	2.4%
Tampa	12.1%	12.1%	10.7%	12.7%	9.2%	3.2%
Washington, DC	13.5%	17.6%	8.9%	15.0%	9.1%	2.9%
National	14.4%	16.3%	12.0%	15.6%	10.1%	3.6%

A3.6. Metro-level upper-quartile energy burdens based on race/ethnicity, age, and tenure status (25% of households in each group have a burden above the upper-quartile threshold)

Metro area	White (non-Hispanic)	Black	Hispanic	Older adults (65+)	Renter	Owner
Atlanta	5.4%	8.1%	7.4%	9.8%	7.2%	6.2%
Baltimore	5.0%	8.3%	4.9%	8.0%	6.7%	5.1%
Birmingham	6.7%	11.8%	8.7%	10.7%	10.4%	6.8%
Boston	5.6%	8.1%	7.7%	9.0%	6.8%	5.6%
Chicago	4.2%	8.5%	4.9%	7.5%	6.0%	4.4%
Dallas	4.3%	5.8%	6.0%	7.0%	5.1%	4.8%
Detroit	6.3%	9.4%	7.2%	9.0%	8.9%	6.3%
Houston	4.4%	6.6%	6.1%	8.0%	6.2%	4.8%
Las Vegas	4.6%	6.1%	5.0%	6.1%	5.3%	4.3%
Los Angeles	3.6%	6.5%	5.0%	6.1%	5.1%	3.8%
Miami	4.4%	6.9%	5.8%	8.3%	6.4%	5.0%
Minneapolis	3.5%	4.4%	4.5%	5.4%	4.2%	3.5%
New York City	5.4%	8.2%	7.9%	10.1%	7.2%	5.3%
Oklahoma City	5.4%	7.4%	6.6%	7.7%	6.8%	5.2%
Philadelphia	5.2%	10.2%	9.2%	8.4%	7.9%	5.5%
Phoenix	4.8%	6.2%	6.0%	7.0%	5.2%	5.2%
Richmond	4.1%	7.0%	5.8%	6.8%	5.5%	4.4%
Riverside	6.7%	7.3%	6.9%	9.2%	7.2%	6.4%
Rochester	6.2%	11.6%	11.4%	9.0%	8.1%	6.1%
San Antonio	4.6%	5.2%	6.4%	7.9%	5.5%	5.3%
San Francisco	2.5%	5.3%	3.6%	4.7%	3.0%	2.8%
San Jose	2.8%	3.7%	3.4%	5.0%	3.1%	2.8%
Seattle	3.2%	4.5%	4.1%	5.1%	3.6%	3.2%
Tampa	5.0%	7.1%	6.3%	6.5%	5.6%	5.2%
Washington, DC	3.0%	5.1%	5.1%	6.0%	4.4%	3.6%
National	5.5%	8.4%	6.5%	8.1%	7.1%	5.4%

A3.7. Metro-level upper-quartile energy burdens based on building type (25% of households in each group have a burden above the upper-quartile threshold)

Metro area	Single family	Multifamily (5+ units)	Low-income multifamily (≤200% FPL, 5+ units)	Built before 1980	Built after 1980
Atlanta	6.6%	5.3%	11.7%	8.1%	5.8%
Baltimore	5.5%	5.5%	5.5%	6.9%	4.0%
Birmingham	7.3%	6.5%	13.9%	9.7%	6.3%
Boston	5.6%	5.6%	11.7%	6.2%	4.9%
Chicago	4.5%	5.3%	12.7%	5.5%	4.0%
Dallas	5.1%	4.2%	7.9%	6.0%	4.6%
Detroit	6.8%	6.0%	9.6%	7.5%	5.7%
Houston	5.1%	5.1%	9.8%	6.1%	4.8%
Las Vegas	4.7%	4.7%	10.9%	6.7%	4.4%
Los Angeles	4.4%	4.4%	8.7%	4.5%	4.1%
Miami	5.2%	5.5%	10.0%	6.2%	4.8%
Minneapolis	3.6%	3.3%	7.7%	3.9%	3.3%
New York City	6.3%	6.6%	15.0%	5.9%	6.4%
Oklahoma City	5.5%	6.8%	10.2%	6.9%	4.7%
Philadelphia	6.2%	5.8%	12.1%	7.0%	4.9%
Phoenix	5.1%	4.2%	7.3%	6.0%	4.6%
Richmond	4.7%	4.0%	8.8%	6.0%	3.9%
Riverside	6.5%	6.9%	9.9%	7.8%	5.8%
Rochester	6.5%	6.3%	9.9%	7.1%	5.9%
San Antonio	5.5%	4.3%	9.2%	7.5%	4.5%
San Francisco	3.0%	2.6%	11.0%	2.9%	2.8%
San Jose	3.0%	2.6%	8.9%	3.1%	2.5%
Seattle	3.2%	3.2%	6.8%	3.6%	3.1%
Tampa	5.2%	4.4%	9.2%	6.5%	4.5%
Washington, DC	4.0%	3.2%	9.1%	4.5%	3.2%
National	5.8%	5.3%	10.1%	6.7%	5.3%

APPENDIX B.
High and Severe Energy Burdens

This section includes 2017 population data from the American Housing Survey (AHS) Table Creator for both national and metropolitan statistical area samples. www.census.gov/programs-surveys/ahs/data/interactive/ahstablecreator.html.

Appendix B.1–National High and Severe Energy Burdens

B1.1. Total national households in each subgroup, and each subgroup's total households with a high energy burden (≥6%) and total households with severe energy burden (≥10%)

Category	Subgroup	Total households	Percentage highly burdened (≥6%)	Total highly burdened households (≥6%)	Percentage severely burdened (≥10%)	Total severely burdened households (≥10%)
Income	All households	121,560,000	25%	30,585,830	13%	15,861,674
	Low-income (≤200% FPL)	38,551,000	67%	25,776,144	40%	15,383,432
	Non-low-income (>200% FPL)	83,009,000	6%	5,214,246	1%	738,779
Race/ ethnicity	Black	16,552,000	36%	5,995,213	21%	3,469,788
	Native American	1,483,000	36%	541,155	19%	283,884
	Hispanic	16,496,000	28%	4,572,335	14%	2,250,966
	White (non-Hispanic)	80,550,000	23%	21,924,520	11%	10,485,640
Age	Older adults (65+)	34,929,000	36%	12,487,949	19%	6,701,933
Tenure	Renters	43,993,000	30%	13,218,332	17%	7,290,945
	Owners	77,567,000	22%	17,174,847	11%	8,431,501
Housing type	Low-income multifamily (5+ units) and low-income (≤200% FPL)	9,345,000	47%	4,413,429	26%	2,408,442
	Small multifamily (2–4 units)	8,363,000	47%	3,949,653	26%	2,155,356
	Manufactured homes	6,727,000	45%	2,999,580	25%	1,709,320
	Built before 1980	55,723,000	29%	15,911,480	15%	8,392,366
	Single family	85,791,000	24%	20,831,649	12%	10,476,575
	Multifamily (5+ units)	20,605,000	22%	4,572,668	12%	2,449,125
	Built after 1980	65,838,000	21%	14,114,223	11%	7,137,071

Appendix B.2–Regional High and Severe Energy Burdens

B2.1. Total households in each region, and each region's total households with a high energy burden (≥6%) and total households with severe energy burden (≥10%)

Region	Total households in region	Percentage highly burdened (≥6%)	Total highly burdened households (≥6%)	Percentage severely burdened (≥10%)	Total severely burdened households (≥10%)
East North Central	18,522,000	29%	5,371,380	15%	2,778,300
East South Central	7,417,000	38%	2,818,460	21%	1,557,570
Middle Atlantic	16,019,000	29%	4,645,510	16%	2,563,040
Mountain	8,916,000	21%	1,872,360	11%	980,760
New England	5,809,000	29%	1,684,610	15%	871,350
Pacific	18,305,000	18%	3,294,900	9%	1,647,450
South Atlantic	23,974,000	26%	6,233,240	14%	3,356,360
West North Central	8,527,000	25%	2,131,750	12%	1,023,240
West South Central	14,070,000	25%	3,517,500	13%	1,829,100
National	121,560,000	25%	30,585,830	13%	15,861,674

B2.2. Total low-income households in each region, and each region's total low-income households with a high energy burden (≥6%) and total low-income households with severe energy burden (≥10%)

Region	Total low-income households in region	Percentage highly burdened (≥6%)	Total highly burdened low-income households (≥6%)	Percentage severely burdened (≥10%)	Total severely burdened low-income households (≥10%)
East North Central	5,979,000	74%	4,424,460	45%	2,690,550
East South Central	2,976,000	74%	2,202,240	46%	1,368,960
Middle Atlantic	4,827,000	72%	3,475,440	48%	2,316,960
Mountain	2,719,000	58%	1,577,020	33%	897,270
New England	1,621,000	75%	1,215,750	52%	842,920
Pacific	5,064,000	57%	2,886,480	33%	1,671,120
South Atlantic	8,042,000	69%	5,548,980	41%	3,297,220
West North Central	2,297,000	66%	1,516,020	39%	895,830
West South Central	5,026,000	66%	3,317,160	36%	1,809,360
National	38,551,000	67%	25,776,144	40%	15,383,432

B2.3. Total Black households in each region, and each region's total Black households with a high energy burden (≥6%) and total Black households with severe energy burden (≥10%)

Region	Total Black households in region	Percentage highly burdened (≥6%)	Total highly burdened Black households (≥6%)	Percentage severely burdened (≥10%)	Total severely burdened Black households (≥10%)
East North Central	2,336,000	43%	1,004,480	25%	584,000
East South Central	1,595,000	51%	813,450	31%	494,450
Middle Atlantic	2,437,000	38%	926,060	25%	609,250
Mountain	359,000	27%	96,930	13%	46,670
New England	401,000	33%	132,330	17%	68,170
Pacific	1,077,000	26%	280,020	15%	161,550
South Atlantic	5,485,000	35%	1,919,750	20%	1,097,000
West North Central	585,000	40%	234,000	24%	140,400
West South Central	2,277,000	34%	774,180	19%	432,630
National	16,552,000	36%	5,995,213	21%	3,469,788

B2.4. Total Hispanic households in each region, and each region's total Hispanic households with a high energy burden (≥6%) and total Hispanic households with severe energy burden (≥10%)

Region	Total Hispanic households in region	Percentage highly burdened (≥6%)	Total highly burdened Hispanic households (≥6%)	Percentage severely burdened (≥10%)	Total severely burdened Hispanic households (≥10%)
East North Central	1,083,000	26%	281,580	12%	129,960
East South Central	197,000	38%	74,860	23%	45,310
Middle Atlantic	2,052,000	38%	779,760	22%	451,440
Mountain	1,721,000	27%	464,670	13%	223,730
New England	563,000	40%	225,200	23%	129,490
Pacific	4,466,000	23%	1,027,180	11%	491,260
South Atlantic	2,695,000	26%	700,700	12%	323,400
West North Central	360,000	26%	93,600	15%	54,000
West South Central	3,359,000	31%	1,041,290	15%	503,850
National	16,496,000	28%	4,572,335	14%	2,250,966

B2.5. Total older adult (65+) households in each region, and each region's total older adult (65+) households with a high energy burden (≥6%) and total older adult (65+) households with severe energy burden (≥10%)

Region	Total older adult (65+) households in MSA	Percentage highly burdened (≥6%)	Total highly burdened older adult households (≥6%)	Percentage severely burdened (≥10%)	Total severely burdened older adult households (≥10%)
East North Central	4,711,000	39%	1,837,290	20%	942,200
East South Central	1,902,000	49%	931,980	26%	494,520
Middle Atlantic	4,228,000	41%	1,733,480	23%	972,440
Mountain	2,258,000	30%	677,400	15%	338,700
New England	1,578,000	41%	646,980	24%	378,720
Pacific	4,328,000	27%	1,168,560	14%	605,920
South Atlantic	6,402,000	37%	2,368,740	21%	1,344,420
West North Central	2,202,000	32%	704,640	17%	374,340
West South Central	3,058,000	37%	1,131,460	21%	642,180
National	34,929,000	36%	12,487,949	19%	6,701,933

B2.6. Total renting households in each region, and each region's total renting households with a high energy burden (≥6%) and total renting households with severe energy burden (≥10%)

Region	Total renting households in region	Percentage highly burdened (≥6%)	Total highly burdened renting households (≥6%)	Percentage severely burdened (≥10%)	Total severely burdened renting households (≥10%)
East North Central	5,945,000	37%	2,199,650	21%	1,248,450
East South Central	2,458,000	46%	1,130,680	28%	688,240
Middle Atlantic	6,279,000	34%	2,134,860	21%	1,318,590
Mountain	3,091,000	24%	741,840	12%	370,920
New England	2,092,000	34%	711,280	19%	397,480
Pacific	7,910,000	21%	1,661,100	11%	870,100
South Atlantic	8,395,000	31%	2,602,450	17%	1,427,150
West North Central	2,616,000	34%	889,440	19%	497,040
West South Central	5,207,000	31%	1,614,170	17%	885,190
National	43,993,000	30%	13,218,332	17%	7,290,945

Appendix B.3—Metro Area High and Severe Energy Burdens

B3.1. Total households in each MSA, and each MSA's total households with a high energy burden (≥6%) and total households with severe energy burden (≥10%)

Metro area	Total households in MSA	Percentage highly burdened (≥6%)	Total highly burdened households (≥6%)	Percentage severely burdened (≥10%)	Total severely burdened households (≥10%)
Atlanta	2,108,800	28%	589,430	14%	287,711
Baltimore	1,047,600	23%	237,681	11%	120,345
Birmingham	447,000	34%	153,330	18%	80,995
Boston	1,853,800	24%	447,358	12%	230,652
Chicago	3,526,500	20%	704,117	10%	362,906
Dallas	2,564,700	19%	483,475	8%	216,838
Detroit	1,723,300	30%	518,698	16%	269,687
Houston	2,329,000	21%	499,379	11%	249,689
Las Vegas	798,600	18%	145,680	10%	80,347
Los Angeles	4,395,700	17%	768,453	9%	390,770
Miami	2,090,600	23%	476,674	12%	249,435
Minneapolis	1,379,600	12%	159,048	5%	71,714
New York City	7,428,000	25%	1,859,460	15%	1,111,740
Oklahoma City	515,900	24%	124,637	11%	57,920
Philadelphia	2,308,400	26%	609,507	14%	332,798
Phoenix	1,685,600	21%	351,448	10%	165,189
Richmond	489,500	17%	85,086	9%	46,342
Riverside	1,314,500	29%	382,285	15%	197,493
Rochester	439,700	29%	127,262	15%	64,726
San Antonio	805,700	22%	176,022	11%	88,011
San Francisco	1,706,200	10%	170,620	6%	100,622
San Jose	657,700	11%	71,468	6%	38,953
Seattle	1,485,700	11%	170,423	6%	83,837
Tampa	1,182,800	21%	248,937	11%	127,945
Washington, DC	2,178,800	14%	299,167	7%	149,583
National	120,062,818	25%	30,585,830	13%	15,861,674

B3.2. Total low-income households in each MSA, and each MSA's total low-income households with a high energy burden (≥6%) and total low-income households with severe energy burden (≥10%)

Metro area	Total low-income households in MSA	Percentage highly burdened (≥6%)	Total highly burdened low-income households (≥6%)	Percentage severely burdened (≥10%)	Total severely burdened low-income households (≥10%)
Atlanta	589,900	79%	466,021	48%	283,152
Baltimore	241,200	77%	185,724	52%	125,424
Birmingham	156,000	82%	127,920	54%	84,240
Boston	412,700	74%	305,398	51%	210,477
Chicago	1,025,400	68%	697,272	39%	399,906
Dallas	692,500	49%	339,325	31%	214,675
Detroit	551,700	80%	441,360	51%	281,367
Houston	731,100	61%	445,971	34%	248,574
Las Vegas	253,700	55%	139,535	33%	83,721
Los Angeles	1,371,300	50%	685,650	27%	370,251
Miami	820,900	57%	467,913	31%	254,479
Minneapolis	256,900	57%	146,433	32%	82,208
New York City	2,248,400	70%	1,573,880	48%	1,079,232
Oklahoma City	155,400	68%	105,672	37%	57,498
Philadelphia	652,300	74%	482,702	48%	313,104
Phoenix	507,800	59%	299,602	32%	162,496
Richmond	122,100	64%	78,144	40%	48,840
Riverside	453,700	71%	322,127	44%	199,628
Rochester	137,400	73%	100,302	46%	63,204
San Antonio	260,800	62%	161,696	35%	91,280
San Francisco	326,600	51%	166,566	32%	104,512
San Jose	121,500	54%	65,610	32%	38,880
Seattle	290,000	50%	145,000	28%	81,200
Tampa	377,900	61%	230,519	36%	136,044
Washington, DC	399,200	60%	239,520	36%	143,712
National	38,551,000	67%	25,776,144	40%	15,383,432

B3.3. Total Black households in each MSA, and each MSA's total Black households with a high energy burden (≥6%) and total Black households with severe energy burden (≥10%)

Metro area	Total Black households in MSA	Percentage highly burdened (≥6%)	Total highly burdened Black households (≥6%)	Percentage severely burdened (≥10%)	Total severely burdened Black households (≥10%)
Atlanta	789,500	36%	284,220	21%	165,795
Baltimore	324,100	34%	110,194	20%	64,820
Birmingham	137,000	47%	64,390	30%	41,100
Boston	157,900	32%	50,528	16%	25,264
Chicago	682,800	37%	252,636	21%	143,388
Dallas	466,000	25%	116,500	14%	65,240
Detroit	427,900	43%	183,997	23%	98,417
Houston	482,400	29%	139,896	15%	72,360
Las Vegas	112,600	26%	29,276	18%	20,268
Los Angeles	372,200	27%	100,494	15%	55,830
Miami	459,500	29%	133,255	18%	82,710
Minneapolis	113,000	15%	16,950	7%	7,910
New York City	1,459,600	32%	467,072	21%	306,516
Oklahoma City	61,000	32%	19,520	17%	10,370
Philadelphia	542,900	39%	211,731	25%	135,725
Phoenix	107,200	26%	27,872	15%	16,080
Richmond	153,500	28%	42,980	15%	23,025
Riverside	129,300	30%	38,790	17%	21,981
Rochester	48,000	44%	21,120	29%	13,920
San Antonio	61,500	20%	12,300	11%	6,765
San Francisco	157,900	24%	37,896	15%	23,685
San Jose	20,600	14%	2,884	11%	2,266
Seattle	94,100	14%	13,174	6%	5,646
Tampa	144,500	28%	40,460	18%	26,010
Washington, DC	631,200	21%	132,552	10%	63,120
National	16,552,000	36%	5,995,213	21%	3,469,788

B3.4. Total Hispanic households in each MSA, and each MSA's total Hispanic households with a high energy burden (≥6%) and total Hispanic households with severe energy burden (≥10%)

Metro area	Total Hispanic households in MSA	Percentage highly burdened (≥6%)	Total highly burdened Hispanic households (≥6%)	Percentage severely burdened (≥10%)	Total severely burdened Hispanic households (≥10%)
Atlanta	168,100	35%	58,835	14%	23,534
Baltimore	42,800	21%	8,988	8%	3,424
Birmingham	14,400	40%	5,760	18%	2,592
Boston	184,900	30%	55,470	17%	31,433
Chicago	561,600	19%	106,704	9%	50,544
Dallas	592,600	25%	148,150	10%	59,260
Detroit	55,200	38%	20,976	15%	8,280
Houston	706,000	25%	176,500	11%	77,660
Las Vegas	186,600	18%	33,588	10%	18,660
Los Angeles	1,589,200	20%	317,840	10%	158,920
Miami	884,800	24%	212,352	12%	106,176
Minneapolis	60,500	16%	9,680	10%	6,050
New York City	1,544,500	33%	509,685	19%	293,455
Oklahoma City	52,300	29%	15,167	16%	8,368
Philadelphia	154,100	45%	69,345	24%	36,984
Phoenix	378,300	25%	94,575	11%	41,613
Richmond	25,100	24%	6,024	11%	2,761
Riverside	579,000	31%	179,490	15%	86,850
Rochester	25,500	44%	11,220	26%	6,630
San Antonio	400,900	27%	108,243	14%	56,126
San Francisco	284,300	12%	34,116	8%	22,744
San Jose	139,200	13%	18,096	7%	9,744
Seattle	109,600	15%	16,440	7%	7,672
Tampa	188,300	27%	50,841	16%	30,128
Washington, DC	252,700	19%	48,013	6%	15,162
National	16,496,000	28%	4,572,335	14%	2,250,966

B3.5. Total older adult (65+) households in each MSA, and each MSA's total older adult (65+) households with a high energy burden (≥6%) and total older adult (65+) households with severe energy burden (≥10%)

Metro area	Total older adult (65+) households in MSA	Percentage highly burdened (≥6%)	Total highly burdened older adult households (≥6%)	Percentage severely burdened (≥10%)	Total severely burdened older adult households (≥10%)
Atlanta	490,700	44%	215,908	24%	117,768
Baltimore	107,700	34%	36,618	18%	19,386
Birmingham	127,800	48%	61,344	27%	34,506
Boston	516,400	38%	196,232	22%	113,608
Chicago	976,800	31%	302,808	16%	156,288
Dallas	540,500	29%	156,745	17%	91,885
Detroit	493,400	41%	202,294	22%	108,548
Houston	503,200	34%	171,088	20%	100,640
Las Vegas	204,400	26%	53,144	15%	30,660
Los Angeles	1,184,600	26%	307,996	14%	165,844
Miami	712,800	35%	249,480	20%	142,560
Minneapolis	339,300	22%	74,646	10%	33,930
New York City	2,162,800	39%	843,492	26%	562,328
Oklahoma City	123,800	35%	43,330	17%	21,046
Philadelphia	674,400	37%	249,528	21%	141,624
Phoenix	502,700	30%	150,810	14%	70,378
Richmond	131,100	29%	38,019	15%	19,665
Riverside	368,300	42%	154,686	24%	88,392
Rochester	133,600	39%	52,104	20%	26,720
San Antonio	188,100	35%	65,835	18%	33,858
San Francisco	498,900	18%	89,802	10%	49,890
San Jose	171,000	20%	34,200	11%	18,810
Seattle	361,100	19%	68,609	9%	32,499
Tampa	402,500	30%	120,750	14%	56,350
Washington, DC	546,800	25%	136,700	14%	76,552
National	34,929,000	36%	12,487,949	19%	6,701,933

B3.6. Total renting households in each MSA, and each MSA's total renting households with a high energy burden (≥6%) and total renting households with severe energy burden (≥10%)

Metro area	Total renting households in MSA	Percentage highly burdened (≥6%)	Total highly burdened renting households (≥6%)	Percentage severely burdened (≥10%)	Total severely burdened renting households (≥10%)
Atlanta	794,400	31%	246,264	16%	127,104
Baltimore	369,100	30%	110,730	16%	59,056
Birmingham	141,700	47%	66,599	28%	39,676
Boston	715,000	28%	200,200	15%	107,250
Chicago	1,238,200	26%	321,932	14%	173,348
Dallas	1,060,200	20%	212,040	10%	106,020
Detroit	527,300	40%	210,920	21%	110,733
Houston	896,000	27%	241,920	14%	125,440
Las Vegas	400,900	21%	84,189	12%	48,108
Los Angeles	2,280,900	21%	478,989	11%	250,899
Miami	853,900	27%	230,553	15%	128,085
Minneapolis	407,700	14%	57,078	7%	28,539
New York City	3,643,800	29%	1,056,702	19%	692,322
Oklahoma City	169,200	30%	50,760	15%	25,380
Philadelphia	614,800	35%	215,180	19%	116,812
Phoenix	593,300	21%	124,593	10%	59,330
Richmond	174,500	23%	40,135	13%	22,685
Riverside	479,300	33%	158,169	16%	76,688
Rochester	144,300	36%	51,948	20%	28,860
San Antonio	305,300	22%	67,166	11%	33,583
San Francisco	375,100	13%	48,763	8%	30,008
San Jose	272,200	12%	32,664	7%	19,054
Seattle	613,600	13%	79,768	7%	42,952
Tampa	418,000	23%	96,140	13%	54,340
Washington, DC	801,800	17%	136,306	8%	64,144
National	43,993,000	30%	13,218,332	17%	7,290,945

APPENDIX C.
City- and State-Led Actions to Address High Energy Burdens

C1. City-led actions to reduce high energy burdens

Metro area	Strategy/action	Year enacted	Description	Data source
Atlanta	Plan with energy burden strategy	2017	The Clean Energy plan includes energy burden as a key strategy for achieving the city's clean energy future.	City of Atlanta 2019
	Plan with energy burden goal	2017	The Resilience Strategy includes action to lift energy burden on 10% of Atlanta households.	City of Atlanta 2017
Cincinnati	Plan with energy burden goal	2018	The Green Cincinnati Plan set a goal to reduce household energy burdened by 10% compared to current levels.	City of Cincinnati 2018
	City-led program to reduce energy burdens	2020	The city partnered with Duke Energy Ohio to address the high energy burdens by launching a low-income multifamily energy efficiency pilot program called Warm Up Cincy.	City of Cincinnati 2020
Houston	Plan with energy burden strategy	2018	The Climate Action Plan includes a goal to promote weatherization programs to reduce residential energy consumption and focus on reducing energy burdens of low-income populations.	City of Houston 2020
Minneapolis	Plan with energy burden goal	2013	The Climate Action Plan states that the city will prioritize neighborhoods with high energy burdens for strategy implementation.	City of Minneapolis 2013
	Equity indicator	2013	Climate Action Plan reporting should also include equity indicators to measure whether energy burden reductions are equitable.	
New Orleans	Plan with energy burden goal	2017	The Climate Action Plan includes two strategies to reduce the high energy burdens of the city's residents.	City of New Orleans 2017
Oakland	Equity indicator	2018	Oakland includes energy cost burden as a metric in its 2018 Equity Indicators report.	City of Oakland 2018
Philadelphia	Plan with energy burden goal	2018	The Clean Energy Vision Plan set a goal to eliminate the energy burden for 33% of Philadelphians.	City of Philadelphia 2018
Pittsburgh	City-led program to reduce energy burdens	2019	As part of the Bloomberg Mayor's Challenge, the city created Switch PGH to address high burdens through a civic engagement tool.	City of Pittsburgh 2019
Saint Paul	Plan with energy burden goal	2017	The city set a goal to reduce resident energy burden within 10 years so that no household spends more than 4% of its income on energy bills.	City of Saint Paul 2017

See Appendix for data sources

C2. State-led actions to reduce high energy burden

State	Strategy/action	Year enacted	Description	Data source
Colorado	Demonstration project/pilot program	2018	The Energy Office awarded GRID Alternatives a $1.2 million grant to launch a project to reduce the energy burden of 300 low-income households through renewable energy and energy efficiency investments.	Cook and Shah 2018
New Jersey	State legislation	2020	The NJ Clean Energy Equity Act (S. 2484) aims to use solar, storage, and energy efficiency to bring low-income households and environmental justice communities within or below the state's average energy burden.	New Jersey Legislature 2020
New York	Governor-led executive order	2016	Governor Andrew M. Cuomo issued the Energy Affordability policy to work toward a goal of no New Yorker spending more than 6% of their household income on energy.	New York 2016
Oregon	Governor-led executive order	2018	In response to Governor Kate Brown's Executive Order 17-20, the Oregon Department of Energy, the Oregon Public Utility Commission, and the Oregon Housing and Community Services Department conducted an assessment and created a 10-year plan to reduce energy burdens in Oregon affordable housing.	OR DOE, OR PUC, and OHCS 2018
Pennsylvania	Public Utility Commission study	2019	The Pennsylvania PUC released a report that assessed home energy affordability for low-income customers in the state.	Pennsylvania Public Utility Commission 2019
	Public Utility Commission policy	2020	The Pennsylvania PUC set a new policy to direct utilities to ensure that low-income customers spend no more than 10% (6% for lowest-income customers) of their income on energy bills.	Pennsylvania Public Utility Commission 2019
Washington	Governor-led executive order	2019	As part of Governor Jay Inslee's Clean Energy Transformation Act, the Washington Department of Commerce assessed the energy burdens for low-income households and the energy assistance offered by electric utilities.	Washington State Department of Commerce 2020

APPENDIX D.
Low-Income Energy Efficiency Program Best Practices

This section contains short descriptions of some best practices for low-income energy efficiency programs: coordination, collaboration, and segmentation; funding and financing; effective measures and targeting; evaluation and quality control; and coordination of energy efficiency and renewable energy investments.

Coordination, collaboration, and segmentation

Community engagement and participatory planning can ensure that programs are designed to meet community needs and build trust. By involving the community in the planning process, energy efficiency programs create outcomes that best meet community needs, leverage community networks to achieve higher program participation, and improve visibility and support within the community for program implementers (e.g., a utility or local government). Participatory planning requires effort from program planners, who can follow a set of best practices for optimal success.[21] For example, Professor Tony Reames conducted a community engagement study of Kansas City, Missouri, to understand barriers that low-income households face in participating in weatherization. This stakeholder engagement led to the development of innovative strategies to overcome barriers, such as hiring an all-African American staff to help build trust within the local community.[22]

Statewide coordination models enable consistent low-income program delivery across utilities, WAP implementers, and local jurisdictions. Some states have one implementer for the state's low-income programs who ensures that similar program offerings are available to all customers in the state. States such as California, New Jersey, New York, Colorado, and Massachusetts offer statewide low-income program models that aim to coordinate resources from multiple sources through a single program. For example, California's Energy Saving Assistance Program is offered by all regulated investor-owned utilities across the state. Massachusetts is served by the Low-Income Energy Affordability Network (LEAN), which includes community action agencies, public and private housing owners, government organizations, and public utilities that all work together to provide low-income efficiency solutions in the state.

One-stop-shop program models minimize barriers and allow low-income households to access all available resources in one place. The models provide a single point of contact, universal intake applications, comprehensive technical assistance, and streamlined access to program resources.[23] One-stop-shop models should be replicated in various locations and combine each location's available offerings. Through its Energize Delaware program model, for example, the nonprofit Delaware Sustainable Energy Utility (DESEU) offers a one-stop-shop resource that focuses on a whole-building approach and consolidates available resources directed at both low-income customers and owners of affordable multifamily buildings.

Market segmentation designs programs to meet the specific needs of subsets of highly burdened households, such as people living in affordable multifamily buildings or manufactured housing. Low-income customers are a diverse segment with diverse energy needs. By segmenting customers by key demographic categories, program designers can then work to identify a specific customer segment's energy usage characteristics and program needs. This can lead to more impactful outreach, relationship building, program design, and results. For instance, Eversource partnered with Oracle Utilities–Opower to develop a first-of-kind approach to digitally characterizing and targeting customers that require assistance. This analytical approach can guide utilities in creating programs that are specific to a resident subset or area.[24]

Fuel-neutral programs allow energy efficiency measures to be completed simultaneously in a home regardless of the electric and/or natural gas utilities that service it. This is critical for addressing the high costs associated with delivered fuels (oil, propane) and for coordinating across electric and natural gas utilities. For example, New York's Clean Energy Fund, designed to deliver on the state's Reforming the Energy Vision (REV) commitments, implements energy efficiency initiatives on a fuel-neutral basis. By taking a fuel-neutral approach, New York State can increase energy efficiency at the lowest cost, enable greater greenhouse gas reductions, and stimulate local economic development.[25]

[21] Calvert, K., I. McVey, and A. Kantamneni. 2017. "Placing the 'Community' in Community Energy Planning. Prepared for *Guelph's Community Energy Initiative Task Force* by the Community Energy Knowledge-Action Partnership. DOI: 10.13140/RG.2.2.22817.30562. www.researchgate.net/publication/319141113_Placing_the_'Community'_in_Community_Energy_Planning.

[22] Reames, T. 2016. "A Community-Based Approach to Low-Income Residential Energy Efficiency Participation Barriers." *The International Journal of Justice and Sustainability* Vol 21. www.tandfonline.com/doi/abs/10.1080/13549839.2015.1136995.

[23] Energy Efficiency for All, *One-Stop Shops for the Multifamily Sector*. assets.ctfassets.net/ntcn17ss1ow9/30B8LUDt8GTegjPE8clalF/8c5e68405c9692afb9f11fe898b8653e/EEFA_OneStopShop_Fact_Sheet__2_.pdf.

[24] Lin, J., K.M. Rodgers, S. Kabaca, M. Frades, and D. Ware. 2020. "Energy Affordability in Practice: Oracle Utilities Opower's Business Intelligence to Meet Low and Moderate Income Need at Eversource." *The Electricity Journal*. 33 (9): 1–11. doi.org/10.1016/j.tej.2019.106687.

[25] NYSERDA. Reforming the Energy Vision: Clean Energy Fund, Frequently Asked Questions. www.nyserda.ny.gov/-/media/Files/About/Clean-Energy-Fund/clean-energy-fund-qa.pdf.

Funding and financing

Leveraging diverse funding sources allows programs to address health and safety issues and include greater investment and available measures. Funding for low-income energy efficiency programs often comes from electric and natural gas utility ratepayer dollars, federal WAP and LIHEAP funds, state and local funds, nonprofit resources, and other private funding sources. Leveraging funding from various sources can give program implementers greater flexibility, as some federal and utility funding sources limit the types of measures they fund. Leveraging diverse funding sources can lead to a more comprehensive program outcome that has the flexibility to address health and safety issues and incorporate more complex sets of energy efficiency investments.

Inclusive financing models, such as no-interest loans, loan guarantees, and the elimination of credit requirements, are designed to help low-income households overcome up-front cost barriers to accessing traditional private financing options. Inclusive financing options include Pay As You Save (PAYS) programs and on-bill tariff models, which allow low-income households to install energy efficiency investments that are paid off over time on the customer's bill.[26] In the low-income multifamily sector, limiting or eliminating up-front costs to building owners can help them undertake more substantial energy efficiency projects and overcome barriers related to the competition for scarce funding for capital projects. Low-interest financing and on-bill repayment can help owners spread out their energy efficiency project costs over time.

Align utility and housing finance programs to encourage energy efficiency upgrades in low-income multifamily buildings. Incorporating utility-customer funding in the current climate of affordable housing refinance and redevelopment can yield deeper, more comprehensive energy efficiency improvements. These extensive renovations may involve replacing outdated building systems, and utility-customer funds can be used to help cover the incremental cost of installing more-efficient equipment than would otherwise be required. For example, the Connecticut Green Bank coordinates closely with the state's energy efficiency initiatives led by the state agencies and local utilities to align incentives for affordable financing for both energy efficiency upgrades and rooftop solar installations. The Connecticut Green Bank's financing opportunities complement the available funding for energy efficiency upgrades from the Connecticut Housing Finance Authority and the Connecticut Department of Housing.[27]

Effective measures, messaging, and targeting

Include health and safety measures and healthier building materials to reduce deferral rates and improve indoor air quality, comfort, and long-term health outcomes for program participants. Programs often address health and safety concerns through leveraged funds. However, rather than disqualifying households due to building health and safety issues such as structural problems, mold, or asbestos, utilities and program implementers can combine funding streams to provide health and safety services. For example, the Bronx Healthy Buildings Program aims to reduce asthma-related hospital visits and address the social determinants of health through education, organizing, workforce development, and building upgrades. Energy audits, building inspections, and tenant organizing aim to identify needed repairs and opportunities for energy efficiency improvements.[28]

Prioritize deep energy-saving measures through a single program and/or engagement to achieve high levels of energy savings. Using trusted contractor networks to deliver programs that include savings-based incentives lets contractors focus on deep savings rather than limiting projects to simple direct-install measures. For example, Oncor's Targeted Weatherization Low-Income program first prioritizes deep energy-saving measures such as building-shell weatherization and air sealing, and then focuses on additional measures such as air-conditioning, refrigeration, and lighting.[29]

Integrate direct-installation and rebate programs to encourage more extensive improvements. For low-income single and multifamily projects, direct-installation programs that offer no-cost energy efficiency measures can provide an opportunity to connect with building owners, complete an on-site energy assessment, and encourage owners to take advantage of rebates for more extensive improvements such as HVAC upgrades, weatherization, common-area lighting retrofits, and other building-shell improvements.

Targeting high energy users and vulnerable households to generate the greatest energy savings and impact. By using utility data to identify households with the highest energy use, energy efficiency providers can achieve the greatest energy savings. Even so, energy use should be looked at in combination with other factors

[26] For more information on inclusive financing options, see SEE Action, 2017. *Energy Efficiency Financing for Low- and Moderate Income Households: Current State of the Market, Issues, and Opportunities.* emp.lbl.gov/sites/default/files/news/lmi-final0811.pdf.

[27] See ACEEE's 2018 report, *Our Powers Combined: Energy Efficiency and Solar in Affordable Multifamily Buildings*. aceee.org/research-report/u1804.

[28] buildhealthchallenge.org/communities/awardee-bronx-nyc/.

[29] Gilleo, A., S. Nowak, and A. Drehobl. 2017. *Making a Difference: Strategies for Successful Low-Income Energy Efficiency Programs.* Washington, DC: ACEEE. aceee.org/sites/default/files/publications/researchreports/u1713.pdf.

that lead to household energy vulnerability. Although high energy use can lead to high savings, households with lower energy use can still experience high energy burdens. Efficiency Vermont, for example, changed its program qualification to focus on low-income households with high energy burden rather than low-income households with high energy use. This let the program qualify more customers and target needs to the most vulnerable households.[30]

Incorporate new and emerging technologies in low-income programs. Expanding the technology scope of low-income energy efficiency programs to technologies they do not traditionally incorporate—such as solar PV, smart meters, energy storage, and electric vehicles—can significantly improve energy affordability and equitable access to these technologies for low-income households.[31] Unless we ensure that new technologies are available to low-income and underinvested communities, inequities in access to these technologies will continue to grow. Programs that incorporate these emerging technologies can address access barriers for low-income communities and ensure more equitable distribution of their benefits.

Effectively message programs in ways that provide clear value and actionable guidance. Effective messaging helps achieve high program participation and builds trust and understanding of program benefits. Investing in energy efficiency often takes time and resources for both single and multifamily building owners. Although programs typically focus on energy savings and energy cost reductions benefits, programs must also market the many nonenergy benefits that result from energy efficiency improvements. Further, they should include actionable guidance—that is, clear steps that residents and building owners can take to learn more about program services and enroll in the program.

Evaluation and quality control

Collect and share metrics on program outcomes, equity impacts, and other tracked data to hold implementers accountable to program requirements and goals. These metrics can include factors such as race and/or ethnicity, income status, property ownership, energy burden, and energy vulnerability. Often, program implementers publish demand-side management reports that include metrics on low-income program savings, spending, and customers served. Implementers can report additional equity factors such as energy burden data, demographic data, and participation distribution. For example, VEIC published the *State of Equity Measurement: A Review of Practices in the Clean Energy Industry*, a guide that offers an overview of energy industry metrics for measuring program equity.[32] These include metrics to define target populations, determine disparate impacts, and include representative voices in program design, implementation, evaluation, and oversight.

Conduct robust research and evaluation to assess achieved reductions in energy usage. Such evaluations help document and clarify program performance. Impact evaluations measure the direct and indirect benefits from programs, while process evaluations provide systematic assessments of how programs operate. By completing robust evaluations, program planners can determine how to best improve their programs for greater impact and efficiency, and better meet the needs of the target community.

Include quality control as a core element of the services to ensure that energy efficiency services are effective, and homes are left in a safe condition. Many program implementers incorporate ongoing training for contractors and quality control professionals, viewing this as critical to program success and devoting project funding to regular trainings. Some program administrators also include strict quality control requirements for all projects rather than for a sample, which helps incentivize contractors to perform high-quality work. For example, Ouachita Electric Cooperative's HELP PAY program, a tariff-based residential energy efficiency financing program, evaluates every project after completion and facilitates trainings for its contractors in quality control techniques to ensure that all contractors understand the assessment methodologies.[33]

Incorporate nonenergy benefits into testing. Without monetizing nonenergy benefits, utility-operated low-income energy efficiency programs cost more to implement per household—and are less cost effective by traditional measures—than utility-operated energy efficiency programs serving higher income groups. However, low-income energy programs deliver benefits beyond energy savings to low-income households that are not typically incorporated into traditional cost-effectiveness testing methods. The *National Standard Practice Manual* discusses how low-income program benefits can be considered at the societal level.[34] States can decide to adjust cost-effectiveness tests for

[30] Efficiency Vermont. 2020. *Targeted Communities Program Update*. www.efficiencyvermont.com/trade-partners/targeted-communities-program-update.

[31] Brown, M., A. Soni, M. Lapsa, and K. Southworth. 2020. *Low-Income Energy Affordability: Conclusions from a Literature Review*. ORNL/TM-2019/1150. info.ornl.gov/sites/publications/Files/Pub124723.pdf.

[32] Levin, E., E. Palchak, and R. Stephenson. 2019. *The State of Equity Measurement: A Review of Practices in the Clean Energy Industry*. Winooski, VT: VEIC. www.veic.org/Media/default/documents/resources/reports/equity_measurement_clean_energy_industry.pdf.

[33] Gilleo, A., S. Nowak, and A. Drehobl. 2017. *Making a Difference: Strategies for Successful Low-Income Energy Efficiency Programs*. Washington, DC: ACEEE. aceee.org/sites/default/files/publications/researchreports/u1713.pdf.

[34] National Efficiency Screening Project. 2017. *National Standard Practice Manual*. nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf. Page 58: Societal Low-Income Impacts.

low-income programs to incorporate these additional benefits. For example, Vermont uses the societal cost test as its primary test and incorporates a 15% adder for nonenergy benefits for low-income customers in its cost-effectiveness screening tool. Similarly, Colorado uses the total resource cost test and includes a 50% adder to account for the benefits from low-income programs.

Renewables and workforce

Integrate energy efficiency and solar program offerings to maximize participant benefits. To do this, combined renewable and energy efficiency programs should first invest in energy efficiency to reduce the home's overall energy needs, and then invest in renewable energy so that individual households can install the right size solar system or many households can access community solar options. For example, the Connecticut Green Bank collaborates with PosiGen, a private company, to deliver both solar and energy efficiency to low-income customers. The Green Bank helps PosiGen generate capital to provide 20-year solar leases combined with energy efficiency upgrades to program participants, leading to the most cost-effective investment.[35]

Support the development of a diverse and strong energy efficiency workforce that represents the local community. Ensure that training opportunities are linked to high-quality, well-paid, and stable careers in the energy efficiency and clean energy workforce sector. States and local governments, utilities, and other program implementers can focus on diversifying suppliers, increasing the worker pipeline by offering training for both contracting firms and students, and partnering with skills-training providers and state agencies—all while working to overcome barriers faced by historically excluded community members. Implementers can also co-deliver training for energy efficiency and renewable energy technologies. For example, the Chicago-based nonprofit Elevate Energy coordinates a Clean Energy Jobs Accelerator that trains individuals from economically excluded communities for careers in solar and energy efficiency.

[35] EDF (Environmental Defense Fund) and APPRISE (Applied Public Policy Research Institute for Study and Evaluation). 2018. Low-Income Energy Efficiency. New York. www.edf.org/sites/default/files/documents/liee_national_summary.pdf.

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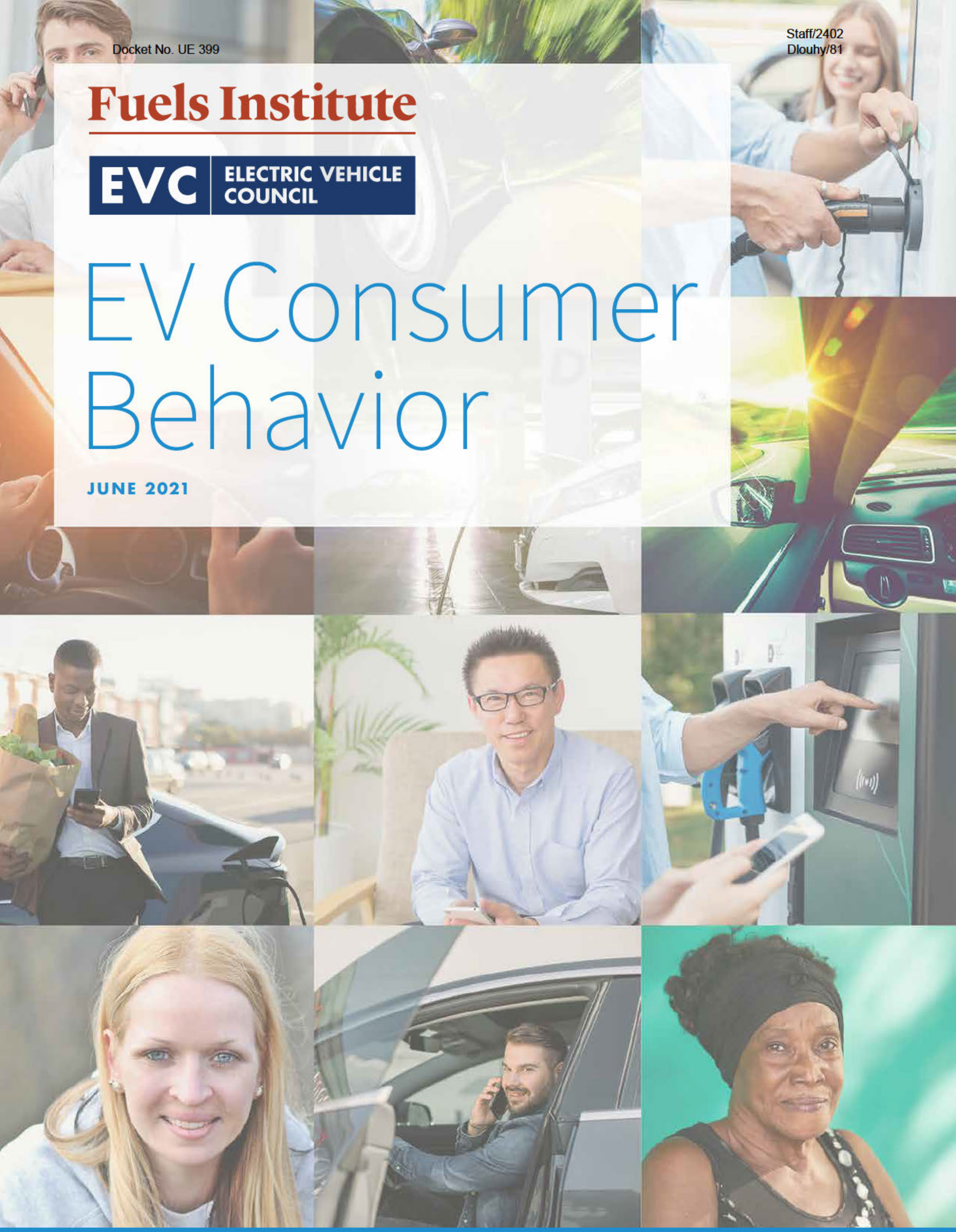


Fuels Institute

EVC ELECTRIC VEHICLE COUNCIL

EV Consumer Behavior

JUNE 2021

Ricardo Inc.
Detroit Technical Center
Van Buren Twp., MI
48111 USA

EXECUTIVE SUMMARY

Electric Vehicle Consumer Behavior

Ricardo Strategic Consulting ("Ricardo") conducted a literature review to better understand how and where consumers drive and recharge their electric vehicles (EVs) and what they would like to experience while recharging in terms of site design, amenities, capabilities, and services.

Ricardo has also analyzed existing literature to both understand current consumer behavior and anticipate how it could evolve over the next 10 years as more consumers purchase EVs. This exercise has been focused on answering five questions:

1. Who is the customer?
2. When and where does the customer recharge?
3. Why does a customer choose a particular recharging facility?
4. How do customers interact with charging equipment?
5. What do customers do at facilities while charging?

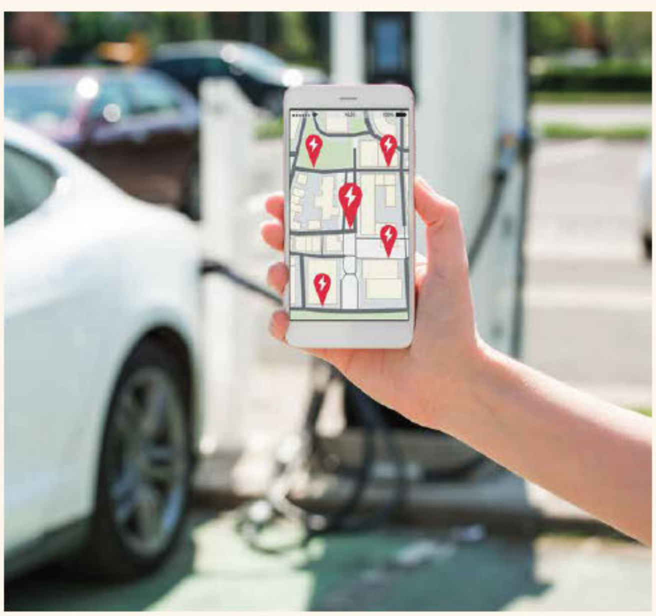
This literature review included various publicly available sources such as existing Ricardo research on consumer preferences; published surveys; federal, state, and local government publications; cross-functional organization publications; scholarly articles; university/institute publications; national lab publications; public policies; and press reports. This was supplemented with persona interviews to exemplify findings.

Key findings that emerged from the literature review are below:

Who is the customer?

- The top demographic of 2019 EV owners are middle-aged white men earning more than $100,000 annually with a college degree or higher and at least one other vehicle in their household.
- 37% of Democrats and 34% of Republicans appear to view EVs positively, and a guaranteed $7,500 tax rebate could make 78% of Democrats and 71% of Republicans more likely to consider an EV during their next purchase or lease (2019).

- EV sales have grown exponentially over the past 10 years; however, the ownership demographic has remained relatively the same. The average EV owner continues to be male, aged 40-55 years old, with an annual household income of more than $100,000 (2019). Mileage driven, however, has increased from 100 miles to 250 miles a week over the years.
- In the next 10 years, EV sales are expected to constitute between 12% and 40% of all light-duty vehicle sales, implying that:
  - EV buyer age could normalize with the broader new vehicle buying trend
  - EVs could become more affordable
  - Number of EV buyers with no provision to charge at home could increase
  - Driving pattern is expected to be similar to the way internal combustion engine (ICE) vehicles are driven
  - Gender distribution could become more balanced
- EV fleet sales are expected to grow in the upcoming years, driven by state mandates.
- Household income, family size, age, driving distance, geographical location, and type of residence tend to influence EV ownership.



- Total cost of ownership (TCO) and payback period are the key drivers in a business' decision involving adoption of EVs in their commercial fleet.
- Affordability, availability, and familiarity appear to be amongst the key factors influencing likelihood of EV purchases.
- EV trips are mostly planned with charging locations in mind, unlike conventional vehicles; however, more daily miles are driven on average in an EV (2020) than in an ICE-powered vehicle.

When and where does the customer recharge?

- EV drivers tend to recharge daily or once every two days, typically overnight at home, and overall, about 70-80% of charging occurs at home or at a workplace parking lot.
- Most EV fleet customers today (2020) operate in a hub-and-spoke network and exclusively recharge their vehicles overnight at their home base.
- The most used public chargers are those where vehicles are typically parked for long periods (e.g., airport parking lots, grocery store, etc.) (2012-2014).
- Most customers drive within their battery range only, using a public charger when making trips longer than their range would permit.
- Drivers of ICE vehicles fill up based on the cost, necessity, and time of the day; 32% only fill up when they see the fuel warning light in the dashboard (2019).
- Nonavailability of chargers at home and making trips longer than the battery range are two of the various reasons why drivers use public charging stations.
- EV charging stations spaced 70 miles from each other on average could provide convenient access to battery electric vehicle (BEV) drivers across the interstate system (2017).

Why does the customer choose a particular public recharging facility?

- EV drivers tend to base their choice of public chargers on various factors, including: speed of charging, need for charging, brand of the charger, compatibility with the electric vehicle supply equipment (EVSE), dependability, availability, identity of charging host/facilities available (e.g., grocery store, gym, etc.), payment options available, and app/in-car interface suggestions.
- Dependability, convenience, cost of use, and the need to travel beyond the EV's battery range appear to have the greatest influence in the choice of charging location (2011-2019).
- Approximately 75% of today's non-Tesla drivers feel the current charging network is "somewhat" or "very adequate" (2017).
- Approximately 46% of BEV drivers (2016) feel availability of direct current fast charging (DCFC) as a feature is not a very big influencer in their EV buying decision.
- More than 80% of EV drivers use three charging locations or fewer away from their home, where they do most of their charging (2011-2014).
- The drivers' decision in picking a brand of charger is influenced by factors such as favoring the provider of the default EV charge card (e.g., Hyundai Ioniq has a ChargePoint card in the glovebox). Other factors include being of the same brand as their home charger, dependability of the network, availability in their primary area of operation of the vehicle, and availability at the places they visit often.
- Fewer than 5% of EV owners rely on smartphone applications ("apps") to find charging stations for daily use, although many EV owners likely have a charging app on their smartphone. Tesla models have point-to-point trip planning with charging integrated in the vehicle, and it is likely other original equipment manufacturers (OEM) will follow (2020).
- Today's EV owners are not deterred by the deficits of the current EV infrastructure and have found ways around the limitations, but for mass adoption, it is critical to understand views of buyers who are not considering buying an EV today (2020).
- ***How do customers interact with charging equipment?***
- Approximately 57% of surveyed EV drivers are willing to pay a premium over at-home charging rates to use a public Level 2 charger, and more than half of EV drivers are willing to pay more for DCFC compared to Level 2 charging when convenient (2020).
- EV drivers preferred optimized charging and to be billed by the kilowatt-hour (kWh) to attain a good balance of cost and time (2016).
- Approximately 77% of people used mobile payments last year, including 80% of 35- to 50-year-old U.S. residents; all top charging network appear to support mobile payments (2019).

What do customers do at facilities while charging?

- Plug-in electric vehicle (PEV) consumers expect to spend 30 minutes to one hour at the charger (2019-2020). Some other studies/surveys suggest that this consumer would prefer an event (15 minutes or less) to minimize downtime in their daily routine. Grocery store visits, dining, and shopping are the most preferred activities while waiting for their EVs to be charged.
- Broadly, free charging while shopping tends to increase dwell time. Kohls found that when provided with free charging, EV owners spend about $1 per minute within an hour window (2015).
- PEV drivers appear to prefer to run errands or to be entertained while charging their vehicle at a public charger (2019).

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INTRODUCTION

The Fuels Institute commissioned Ricardo Strategic Consulting ("Ricardo") to review existing literature to better understand how consumers drive, where they recharge their EVs, and what they would like to experience during a recharging occasion in terms of site design, amenities, capabilities, and services. In addition to this, the study seeks to understand consumer behavior today and anticipate how it might evolve over the next 10 years as more consumers purchase EVs.

Fuels Institute is a not-for-profit organization led by a collaborative group of fuel retailers, fuel producers and refiners, alternative and renewable fuels producers, automobile manufacturers, and others with expertise in the fuels and automotive industries. The Institute delivers comprehensive and balanced research and analysis concerning fuels, vehicles, and related policy issues. The Electric Vehicle Council is a project of the Fuels Institute comprised of organizations seeking to eliminate confusion and provide guidance for success relative to the installation and operation of retail EV charging stations through stakeholder collaboration, objective research, and market education. Ricardo has aligned its research and opinions in this report to a similar unbiased philosophy.

LITERATURE STUDY CONTEXT

The market for EVs is expanding, and there is significant need for charging infrastructure. To ensure that the infrastructure satisfies the needs and interests of EV drivers and site hosts alike, it is important to understand what those drivers want and how they would use the infrastructure. This information would be particularly useful to charger operators to help design appropriate facilities. Furthermore, as the EV market grows, the demographic profile of the EV driver is likely to change and become more diverse. The diversity of future EV drivers could require different designs and amenities to support the various demands of the consumers. Given that charging systems will be long-lived assets that could be in use 10 years or longer following installation, it is essential to better anticipate how drivers will use these systems to ensure the designs remain relevant to driver needs throughout their expected useful life. This literature review is intended to identify trends in EV consumer behavior today, how it has evolved over the past 10 years, and how it could evolve in the next few years to align with the goal of anticipating how drivers will use these systems over the life of the systems.

Ricardo has found that most of the existing research on EV charging preferences is conducted with current EV owners and potential buyers. These owners are likely to use, or work around, the existing infrastructure even with sub-optimal charging speed, density, or site design. Identifying charging preferences of the buyer who is not yet considering EV purchase will be equally important to future infrastructure. This report cites existing literature.

OBJECTIVE OF THE STUDY

In order to understand consumer behavior today, in the past 10 years, and expected trends over the next 10 years, this report has been structured to answer the following broad questions and their sub-questions:

Who is the customer?

- What is the demographic profile of today's EV drivers? How does this compare to the population at large, how has it evolved over the past 10 years, and how might it evolve over the next 10 years?
- Which demographic characteristics most influence EV ownership and behavior?
- How do trips taken in an EV differ, if at all, from those taken in a liquid-fueled vehicle?

When and where does the customer recharge?

- With what frequency do EV drivers recharge their vehicles? Where do consumers recharge their vehicles? What are the factors that influence drivers to initiate a recharging occasion? How does this behavior compare with drivers of liquid-fueled vehicles?
- How often do EV drivers charge at public stations? Why do they choose to charge at a public station versus at home, work, or other locations? What would encourage them to use public charging stations more frequently?
- How much charging infrastructure will be required to service demand compared to the amount of charging infrastructure required to provide consumers with sufficient comfort regarding convenient accessibility of chargers?

Why does the customer choose a particular public recharging facility?

- To what extent does the availability of Level 2 charging influence consumer perception about charging availability, capacity, and convenience compared with DCFC equipment? How would the price of the service influence this perception?
- Is there a difference in consumer perception relative to the identity type of the charging station host, e.g., a restaurant, convenience store, shopping center, grocery store, parking garage, public verses private entity?
- To what extent does the brand of the charger equipment influence selection?
- How often do consumers use apps to find appropriate public charging, and will the use of these apps grow or diminish as EVSE becomes more available?

How do customers interact with charging equipment?

- How willing are consumers to pay for charging services?
- How do they perceive various billing methods?
- How comfortable are they with various payment options?
- Do their perceptions change depending on the identity of the company initiating the transaction?

What do customers do at facilities while charging?

- How much time do drivers expect to spend at a charging station, and what facility features would influence that expected dwell time?
- Which facility features and amenities are most desired by EV drivers and used during a charging occasion? How does this change with variations in dwell time? Which features or amenities yield the greatest influence over an EV driver's decision regarding where to charge?
- Do EV drivers use facility amenities more or less frequently than other customers at the facility?
- How much money do EV drivers spend at these facilities compared with other drivers?

PERSONAS

Personas are created to exemplify predicted individual preferences by conducting internal interviews. Five personas and their daily habits are outlined below. These have been picked to represent various demographics, their use cases, and perceptions of EV ownership and charging. Ricardo formed teams of 4-5 individuals to discuss each persona. This structure helps describe individual character choices with regards to their daily habits and preferences. A short outline of these personas is mentioned below. Details will be found towards the end of the report.

Michael represents the top demographic of today's EV buyer: an affluent, white, 37-year-old man living in the California Bay Area with the EV as a second vehicle. Michael's character is chosen to demonstrate the behavior of a large section of today's EV owners.

Shou is a 49-year-old Asian American man who also owns an EV as a secondary vehicle. His travel needs are limited, and he prefers public transport to driving. Shou's character serves to help understand the benefit of owning an EV when car travel is limited.

Raj is a 28-year-old electrical engineer of Indian origin who lives in an apartment with a common, shared EV charging station. Raj is much younger than the average age of EV owners, and the EV is his only car.

Millicent is a 68-year-old African American woman who lives on a fixed income and owns an EV as her primary vehicle. Millicent's character brings to light the reasoning to own an EV as a means to show her devotion to the eco-conscious ideology. She is one of the rare examples who does not use fast chargers and charges at home on a Level 1 charger.

Amy is a 43-year-old white woman who owns her electrician business and is a prospective buyer of an electric pickup truck. The total cost of operation of an electric truck is attractive given her high daily mileage. Her character helps understand the requirements that need to be met in order to cater to the prospective buyer that finds the current EV infrastructure unsatisfactory.

METHODOLOGY

In compiling this report, Ricardo has researched the following:

1. **Public domain resources, including published surveys; federal, state, and local government publications; cross-functional organization publication; scholarly articles; university/institute publications; national lab publications; public policies; and press reports**

2. **Existing Ricardo studies on user preferences for future mobility (e.g., Ricardo's ongoing engagement with the California Air Resources Board)[1]**

3. **Supplemental persona creation to exemplify individual preferences**

Throughout the report, the terms *PEV*, *BEV*, and *EV* are used frequently. A PEV within this report refers to a combination of both plug-in hybrid electric vehicles (PHEVs) and BEVs. The term *PEV* is primarily used when the study particularly involves both PHEVs and BEVs. The terms *BEV* and *EV* are used interchangeably when referring to BEVs.

The term *PHEV*, in this report, refers to vehicles that use batteries to power an electric motor and use another fuel, such as gasoline, to power an ICE. BEVs or EVs are defined, within this report, as vehicles that have an electric motor instead of an ICE.

The EV Project mentioned in this report refers to the study conducted by the Idaho National Laboratory (INL) in partnership with Electric Transportation Engineering Corporation, Nissan, General Motors, and more than 10,000 other city, regional, and state governments, electric utilities, other organizations, and members of the public.[2] They deployed over 12,000 AC Level 2 (208-240V) charging units and over 100 dual-port DCFC in 20 metropolitan areas. Approximately 8,300 Nissan Leafs, Chevrolet Volts, and smart EQ fortwo vehicles were driven over 125 million miles, and charging-related data for over 4 million charging events was captured between January 1, 2011, and December 31, 2013. This was the largest deployment and evaluation project of EVs and charging infrastructure.

1 Ricardo, "Ricardo awarded key heavy-duty zero-emissions vehicle project by CARB," news release, October 24, 2021, https://ricardo.com/news-and-media/news-and-press/ricardo-awarded-key-heavy-duty-zero-emissions-vehi.

2 "AVTA: The EV Project," Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy, https://www.energy.gov/eere/vehicles/avta-ev-project.

PROJECT REPORT

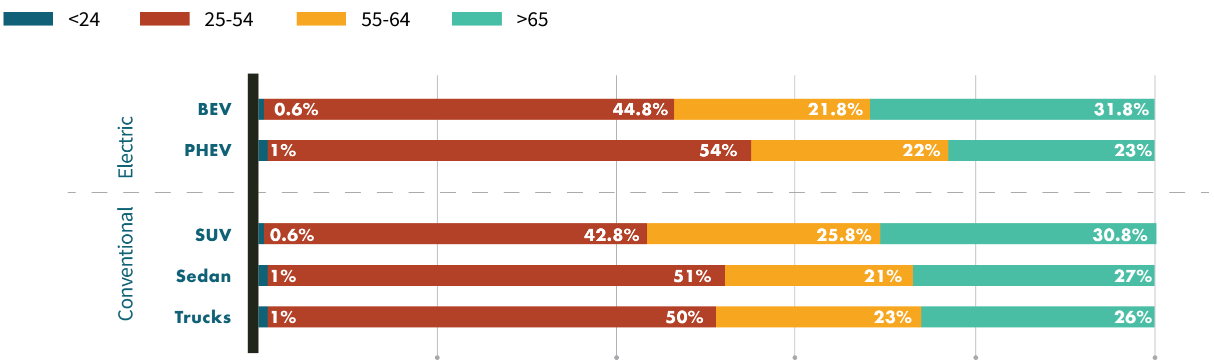
WHO IS THE CUSTOMER?

DEMOGRAPHICS

PEV buyers tend to follow the general trend of new car buyers. The dominant age group for PEV buyers across the board is 25-54 years old, according to Hedges Company's 2019 survey (Figure 1).[3]

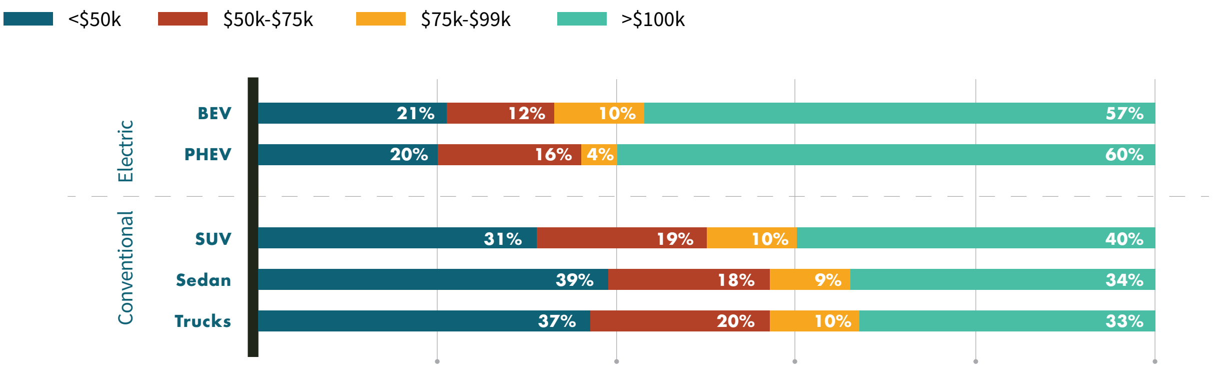
The most dominant annual household income bracket amongst PEV buyers is "greater than $100,000." For conventional vehicles, buyers are almost evenly split between "less than $50,000" and "greater than $100,000" annual household income (Figure 2).[4] The average household annual income of most EV owners is found to be between $125,000 and $150,000, according to the same survey.[5]

FIGURE 1: SPLIT OF NEW CAR BUYERS BASED ON AGE GROUP (2019)



Source: "New Car Buyer Demographics 2020 (Updated)," Hedges & Company (rounded numbers used in some cases)

FIGURE 2: SPLIT OF NEW CAR BUYERS BASED ON ANNUAL HOUSEHOLD INCOME BRACKET (2019)



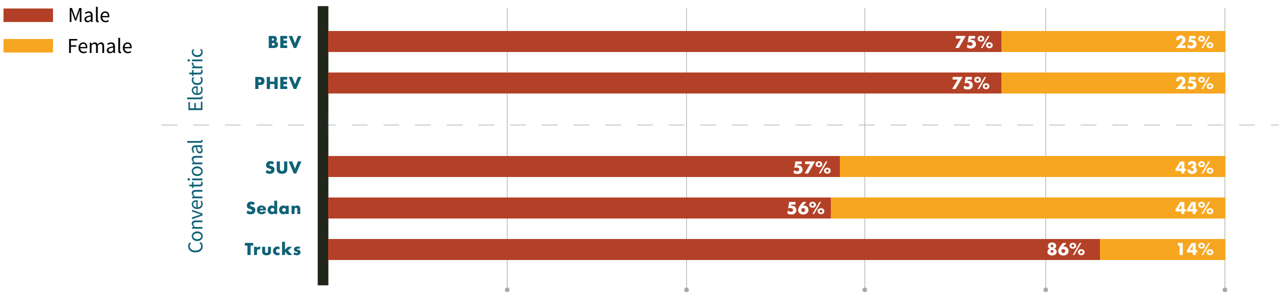
Source: "New Car Buyer Demographics 2020 (Updated)," Hedges & Company

3 "New Car Buyer Demographics 2020 (Updated)," Hedges & Company, accessed October 5, 2020, https://hedgescompany.com/blog/2019/01/new-car-buyer-demographics-2019/.

4 "New Car Buyer Demographics 2020 (Updated)"

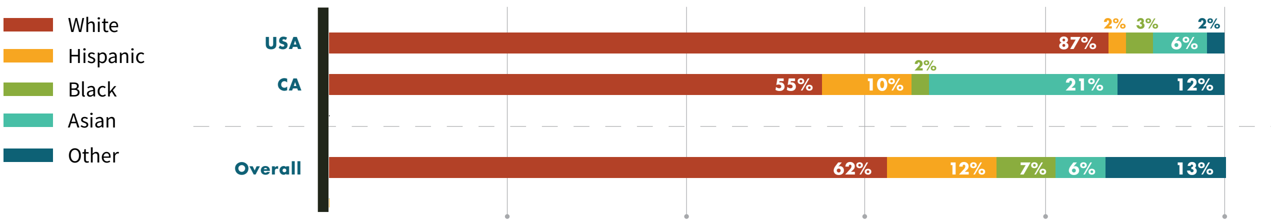
5 Christopher Butler, "Electric Vehicle Prices Finally in Reach of Millennial, Gen Z Car Buyers," CNBC, October 20, 2019, updated: October 21,2019, https://www.cnbc.com/2019/10/20/electric-car-prices-finally-in-reach-of-millennial-gen-z-buyers.html.

FIGURE 3: SPLIT OF NEW CAR BUYERS BASED ON GENDER (2019)



Sources: "New Car Buyer Demographics 2020 (Updated)," Hedges & Company; Farkas et al., Electric Vehicle Ownership Factors, Preferred Safety Technologies, and Commuting Behavior in the United States

FIGURE 4: SPLIT OF PEV BUYERS BASED ON ETHNICITY (USA 2014, CA 2018, OVERALL 2015)



Note: U.S. sample population is 379 EV owners

Sources: Farkas et al., Electric Vehicle Ownership Factors, Preferred Safety Technologies, and Commuting Behavior in the United States*; Erich Muehlegger and David Rapson,* Impacts of Vehicle Policy: Who Buys New and Used Alternative Vehicles?*; Statista Research Department,* Structure of New Vehicle Buyers in the United States, Distributed by Ethnicity Between January and May of 2014 and 2015

As shown in Figure 3,[6] PEV buyers, similar to conventional-fuel truck buyers, are mostly male.[7] Sport utility vehicles (SUV) and sedans have a more balanced distribution amongst male and female buyers.[8]

As shown in Figure 4,[9] PEV buyers nationally in the U.S. are mostly white (87%) according to a study conducted by Morgan State University.[10] The distribution of the white population is slightly elevated in comparison to the distribution of the U.S. population, with 75% white, 13% Black or African American, 6% Asian, and 6% others.[11] Black or African American ethnicity, however, appears to be underrepresented amongst EV buyers. However, in California, according to a survey conducted by the University of California, Davis, and the National Center for Sustainable Transportation, while the distribution of buyers also is mostly white, Asian American PEV buyers appear to closely follow at 21%. This can also be attributed to the fact that California is one of the states with a higher population density of Asian Americans.[12]

6 "New Car Buyer Demographics 2020 (Updated)"; Z. Andrew Farkas, Hyeon-Shic Shin, Seyedehsan Dadvar, and Jessica Molina, *Electric Vehicle Ownership Factors, Preferred Safety Technologies, and Commuting Behavior in the United States* (Charlottesville, VA: Mid-Atlantic Transportation Sustainability University Transportation Center, University of Virginia, February 2017), available at http://www.matsutc.org/wp-content/uploads/2014/07/Environmental-and-Safety-Attributes-of-Electric-Vehicle-Ownership-and-Commuting-Behavior-Public-Policy-and-Equity-Consideration.pdf.

7 "New Car Buyer Demographics 2020 (Updated)"

8 "New Car Buyer Demographics 2020 (Updated)"; Farkas et al., *Electric Vehicle Ownership Factors, Preferred Safety Technologies, and Commuting Behavior in the United States*

9 Farkas et al., *Electric Vehicle Ownership Factors, Preferred Safety Technologies, and Commuting Behavior in the United States*; Erich Muehlegger and David Rapson, *Impacts of Vehicle Policy: Who Buys New and Used Alternative Vehicles?*, prepared by Morgan State University (National Center for Sustainable Transportation, University of California Davis, February 2018), available at https://escholarship.org/uc/item/0tn4m2tx; Statista Research Department, *Structure of New Vehicle Buyers in the United States, Distributed by Ethnicity Between January and May of 2014 and 2015*, May 2016, accessed October 20, 2020, https://www.statista.com/statistics/549852/structure-of-new-vehicle-buyers-united-states-by-ethnicity/.

10 Farkas et al., *Electric Vehicle Ownership Factors, Preferred Safety Technologies, and Commuting Behavior in the United States*

11 "2019: ACS 1-Year Estimates Detailed Tables" (Table ID C02003, Universe: Total Population, Survey/Program: American Community Survey), United States Census Bureau, accessed October 29, 2020, available at https://data.census.gov/cedsci/table?q=race&g=0100000US.04000.001&tid=ACSDT1Y2019.C02003&moe=false&tp=true&hidePreview=true.

12 "2019: ACS 1-Year Estimates Detailed Tables"

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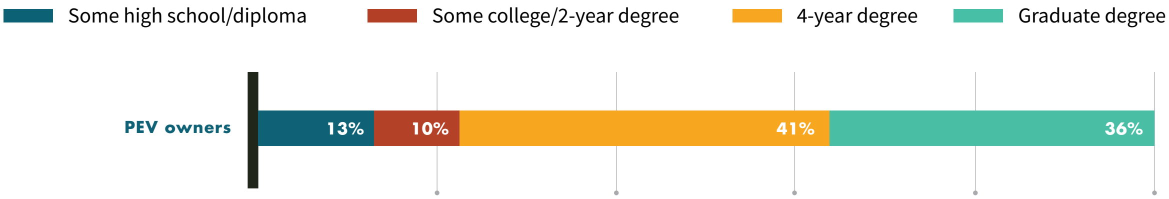
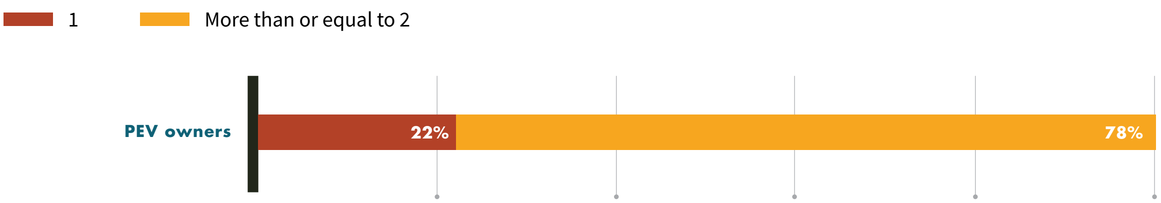
FIGURE 5: SPLIT OF PEV OWNERS BASED ON EDUCATION LEVEL (2017)



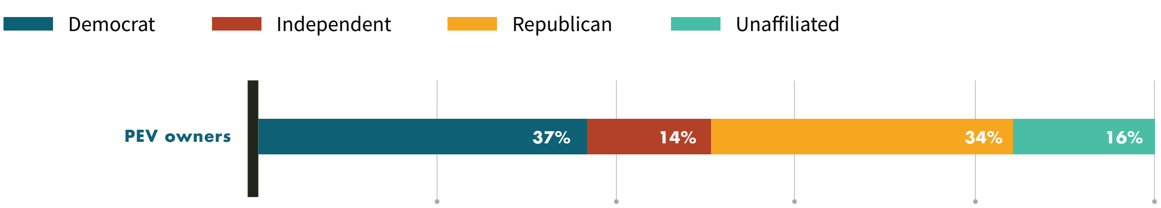
Source: Farkas et al., Electric Vehicle Ownership Factors, Preferred Safety Technologies, and Commuting Behavior in the United States

FIGURE 6: SPLIT OF PEV OWNERS BASED ON NUMBER OF VEHICLES IN HOUSEHOLD (2020)



Source: Ellen Edmonds, "AAA: Owning an Electric Vehicle is the Cure for Most Consumer Concerns"

FIGURE 7: POLITICAL AFFILIATION OF PEV OWNERS (2017)



Source: Farkas et al., Electric Vehicle Ownership Factors, Preferred Safety Technologies, and Commuting Behavior in the United States

Most PEV owners have at least a four-year degree according to the survey conducted by Morgan State University (Figure 5).[13]

AAA's survey of EV owners revealed that 78% of them also owned a gas-powered car (Figure 6).[14]

In a survey conducted by Morgan State University in 2017, it was observed that slightly more Democrats owned PEVs compared to Republicans (Figure 7).[15]

13 Farkas et al., *Electric Vehicle Ownership Factors, Preferred Safety Technologies, and Commuting Behavior in the United States*

14 Ellen Edmonds, "AAA: Owning an Electric Vehicle is the Cure for Most Consumer Concerns," AAA, January 22, 2020, https://newsroom.aaa.com/2020/01/aaa-owning-anelectric-vehicle-is-the-cure-for-most-consumer-concerns/.

15 Farkas et al., *Electric Vehicle Ownership Factors, Preferred Safety Technologies, and Commuting Behavior in the United States*

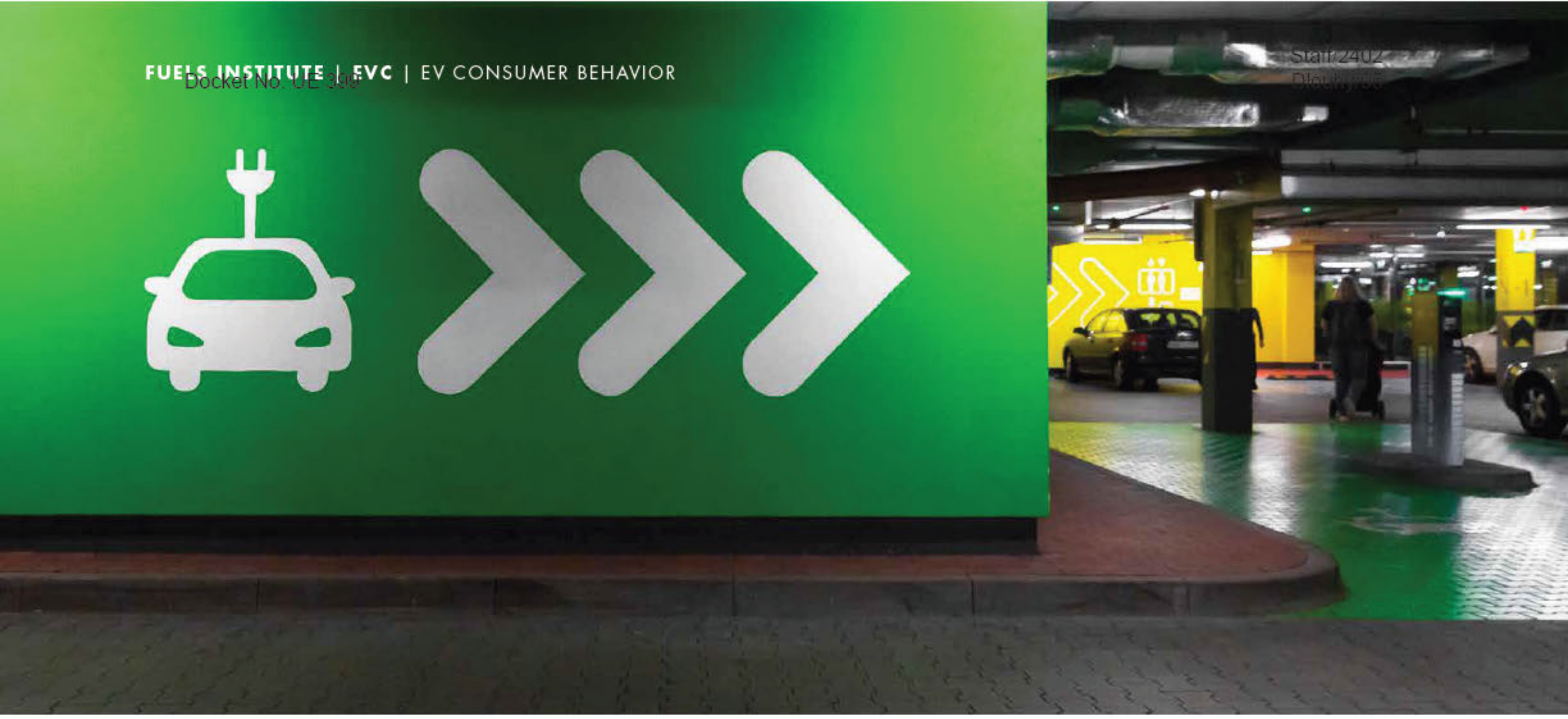
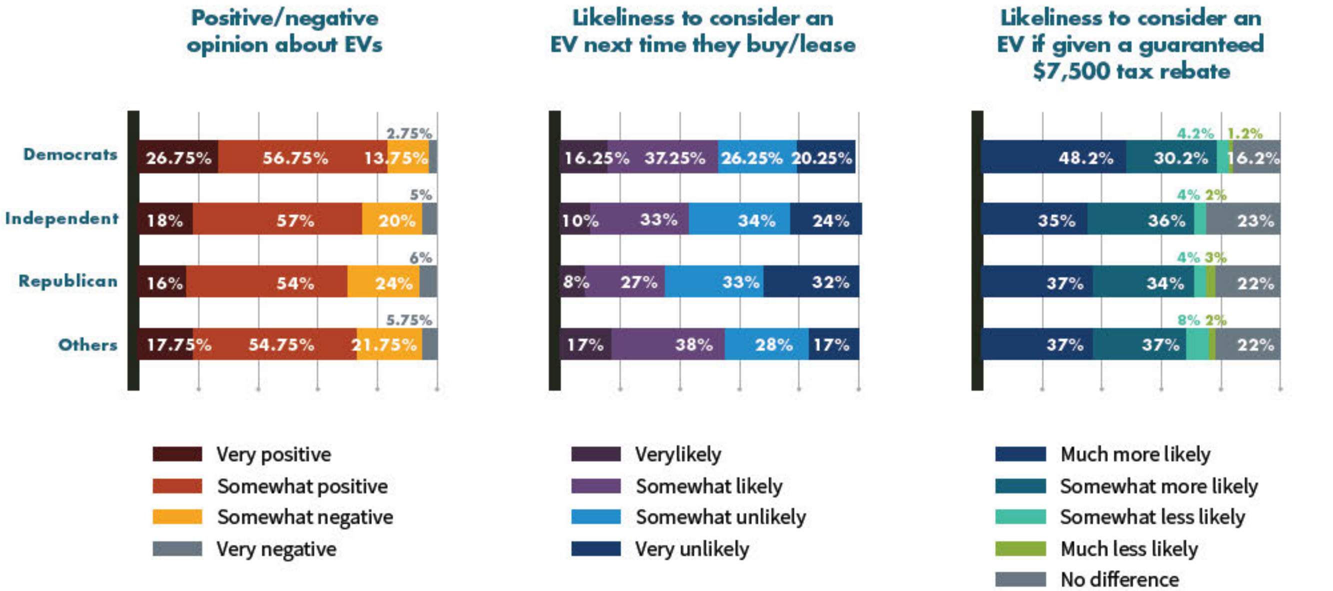


FIGURE 8: VIEWS ON EVS GROUPED BY POLITICAL AFFILIATION (2019)

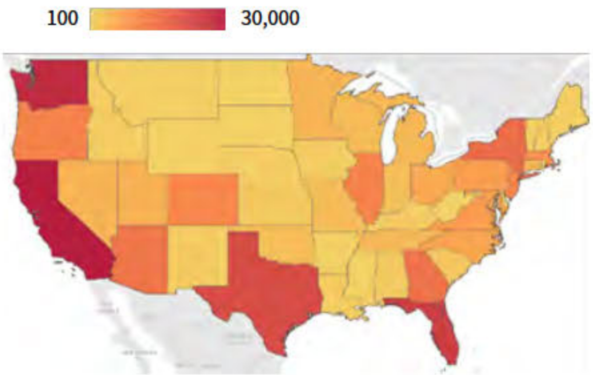


Source: "National Poll Results," Climate Nexus (rounded numbers used in some cases)

In a study conducted by Climate Nexus, Democrats viewed EVs slightly more favorably than Republicans (Figure 8).[16] When asked about the likeliness to consider purchasing or leasing an EV next time, approximately 53% Democrats and approximately 35% Republicans responded affirmatively. When asked if they would consider buying or leasing an EV if they were offered a guaranteed $7,500 tax rebate, their responses changed dramatically: 78% Democrats and 71% Republicans said they are likely to consider one.

16 "National Poll Results," Climate Nexus, 2015, https://climatenexus.org/wp-content/uploads/2015/09/EV-Poll-Results.pdf.

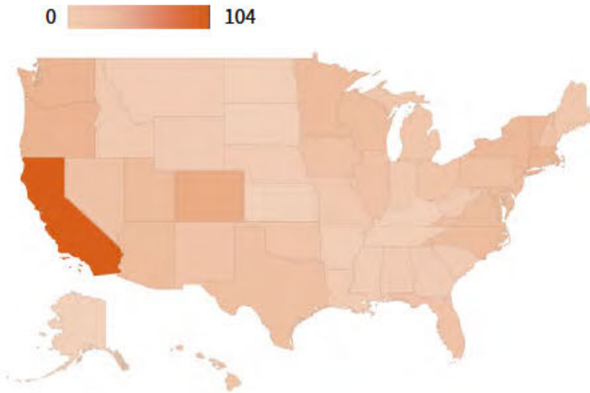
FIGURE 9: HEATMAP OF BEV POPULATION BASED ON NUMBER OF REGISTRATIONS BY STATE (2018)



Note: Total registrations in California is 256,000 but the legend ends at 30,000 to highlight the variation in other states.

Source: "Electric Vehicle Registrations by State," National Renewable Energy Laboratory

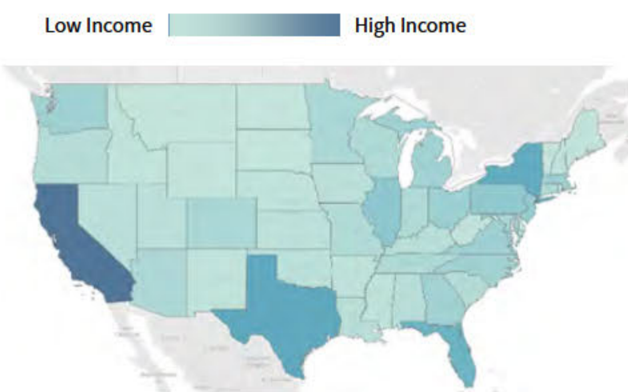
FIGURE 11: EV LAWS AND INCENTIVES (2020)



Note: Darker color indicates a greater number of laws and incentives; California leads at 104.

Source: "Electric Vehicle Laws and Incentives by State" (chart), "Maps and Data — Electric Vehicle Laws and Incentives by State" (webpage), Alternative Fuels Data Center

FIGURE 10: INDIVIDUAL INCOME BY STATE (2018)



Note: Darker color indicates a larger sum of individual income.

Source: "SOI Tax Stats — Individual Income Tax Statistics — 2018 ZIP Code Data (SOI)," Internal Revenue Service

Distribution of BEVs is concentrated along the ZEV (zero-emission vehicle) belt (Figure 9).[17] BEV registrations in California in 2018 were approximately 256,000, which was roughly equal to the BEV registrations in all other states combined (approximately 286,000).[18]

This distribution appears to correspond with individual income in each state (Figure 10)[19] and the EV policies and incentives in each state (Figure 11).[20] When compared to the overall number of vehicles registered by state, EVs constitute a very small percentage (Figure 12).[21]

17 "Electric Vehicle Registrations by State," National Renewable Energy Laboratory, printed March 7, 2020, updated August 2020, accessed October 20, 2020, available at https://afdc.energy.gov/data/10962.

18 "Electric Vehicle Registrations by State;" "U.S. Automobile Registrations in 2018, by State," Statista, March 2021, https://www.statista.com/statistics/196010/total-number-ofregistered-automobiles-in-the-us-by-state/.

19 "SOI Tax Stats — Individual Income Tax Statistics — 2018 ZIP Code Data (SOI)," Internal Revenue Service, 2018, accessed October 20, 2020, available at https://www.irs.gov/statistics/soi-tax-stats-individual-income-tax-statistics-2018-zip-code-data-soi.

20 "Electric Vehicle Laws and Incentives by State" (chart), "Maps and Data — Electric Vehicle Laws and Incentives by State" (webpage), Alternative Fuels Data Center, Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy, accessed October 22, 2020, available at https://afdc.energy.gov/data/10373."""

21 "Electric Vehicle Registrations by State;" "U.S. Automobile Registrations in 2018, by State"

Distribution of BEVs is concentrated along the ZEV (zero-emission vehicle) belt.

BEV registrations in California in 2018 were approximately 256,000, which was roughly equal to the BEV registrations in all other states combined (approximately 286,000).

Despite having the highest number of EV registrations in the U.S., California's BEV population still comprises only approximately 1.7% of the state's overall vehicle registrations (Figure 12). In each of the 10 states with the most EV registrations, those registrations constituted less than 1% of all state vehicle registrations in 2018.

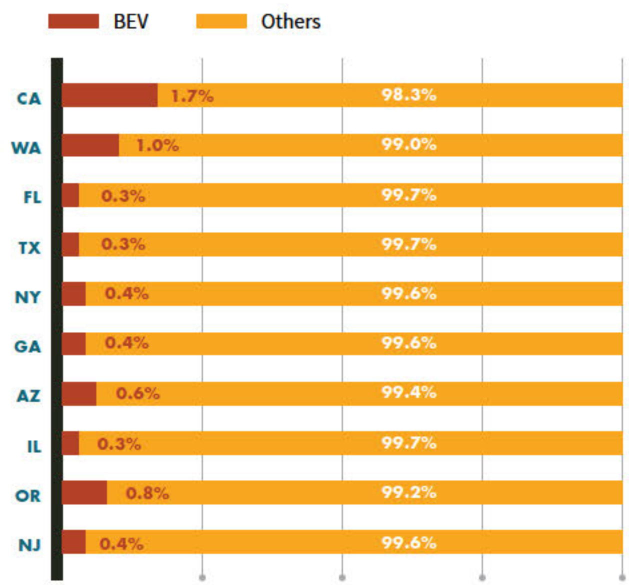
Daily commute lengths of PEV drivers

According to the Federal Highway Administration, in 2017, self-estimated annual mileage indicates an average daily commute between 20 and 35 miles.[22] For EV drivers, however, the average daily commute length is estimated to be between 31 and 39 miles.[23] One reason for this observed trend could be BEVs have a lower cost of fuel and maintenance compared to an ICE-powered vehicle — estimated by AAA as 57% lesser and 65% lesser, respectively. Most EV owners also own a second vehicle in the household, which could be a conventional vehicle. Given the cheaper operating cost of a BEV compared to a conventional vehicle, owners might prefer to use the BEV for a higher number of trips.[24] Another reason could be that the constant increase of both average EV battery range and charging infrastructure has reduced range anxiety for drivers.

EVOLUTION OF EV BUYER DEMOGRAPHICS AND BEHAVIOR OVER THE PAST 10 YEARS

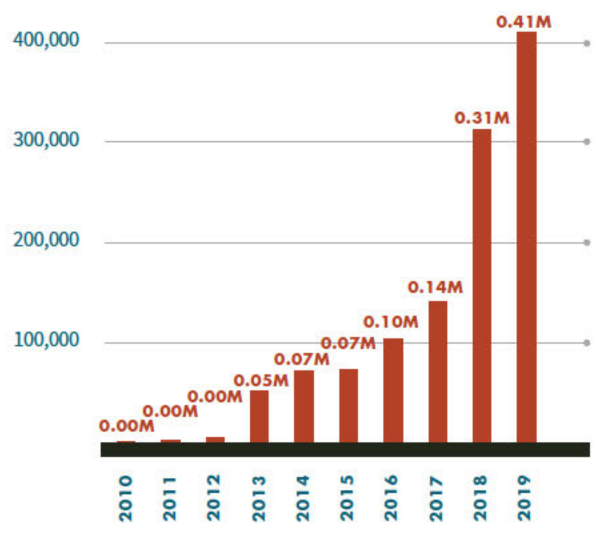
BEV production in the U.S. has been experiencing exponential growth aided by falling battery prices.[25] The spike in 2018 coincides with the Tesla Model 3 introduction (Figure 13).[26]

FIGURE 12: SPLIT OF VEHICLE REGISTRATIONS BY STATE (TOP 10) (2018)



Source: "Electric Vehicle Registrations by State;" "U.S. Automobile Registrations in 2018, by State"

FIGURE 13: BEV PRODUCTION IN THE U.S. (2010-2019)



Source: IHS Markit

22 N. McGuckin and A. Fucci, *Summary of Travel Trends: 2017 National Household Travel Survey* (Washington, DC: Federal Highway Administration, July 2018), available at https://nhts.ornl.gov/assets/2017_nhts_summary_travel_trends.pdf.

23 Ellen Edmonds, "AAA: Owning an Electric Vehicle is the Cure for Most Consumer Concerns"; Daniel Boston and Alyssa Werthman, "Plug-in Vehicle Behaviors: An Analysis of Charging and Driving Behavior of Ford Plug-In Electric Vehicles in the Real World," *World Electric Vehicle Journal* 8 (2016): 926-935, https://doi.org/10.3390/wevj8040926.

24 Ellen Edmonds, "AAA: Owning an Electric Vehicle is the Cure for Most Consumer Concerns"

25 Colin McKerracher, Ali Izadi-Najafabadi, Aleksandra O'Donovan, Nick Albanese, Nikolas Soulopolous, David Doherty, Milo Boers, et al, *Electric Vehicle Outlook 2020* (Bloomberg New Energy Finance, 2020), https://about.bnef.com/electric-vehicle-outlook/.

26 IHS Markit, subscription-only database and forecast utility, accessed October 1, 2020, https://ihsmarkit.com/

FIGURE 14: EVOLUTION OF KEY EV BUYER DEMOGRAPHICS (2012-2021)

	2012	2015	2019
AGE	40–44	45–54	40–55
AVERAGE INCOME	$114k	$114–150k	$125–150k
RESIDENCE	90% vehicle garage	90% vehicle garage	no public data
MILEAGE	~100 per week	~180 per week	~250 per week
GENDER	67% male	74% male	75% male

The PEV buyer's age group has stayed the same over the years (Figure 14).[27] The average household annual income has been consistently over $100,000.[28] Most PEV owners have had a garage with an outlet to charge their vehicle.[29] PEV buyers have mostly been male.[30] Mileage traveled, however, has increased from 100 miles a week to 250 miles a week over the past 10 years.[31] This could be attributed to the fact that both the average battery range on a typical EV and the charging infrastructure have been growing constantly, which helps ease range anxiety for buyers. In addition to this, the cost of operating an EV is less than that of a conventional vehicle, encouraging drivers to drive their EVs more than their other conventional vehicle(s).[32]

The EV fleet has grown over the past 10 years where commercial fleet operators have gained more experience in deploying EVs in the field. EV usage in the commercial sector has evolved from limited-use transit bus applications to medium- and heavy-duty vehicles, delivery vans, and light-duty trucks.[33] A very recent example to this is Amazon's 2020 investment in Rivian to provide vans for its fleet.[34]

27 Deloitte Consulting LLP, *Gaining Traction: A Customer View of Electric Vehicle Mass Adoption in the U.S. Automotive Market*, 2010, https://www.yumpu.com/en/document/read/4198231/gaining-traction-a-customer-view-of-electric-vehicle-mass-adoption-in; Chris Woodyard, "Study: Electric Car Buyers Are Younger but Richer," *USA Today*, May 4, 2015, updated May 7, 2015, https://www.usatoday.com/story/money/cars/2015/05/04/truecar-study-electric-cars-richer/26884511/; "EV Consumer Survey Dashboard," California Clean Vehicle Rebate Project, accessed October 5, 2020, available at https://cleanvehiclerebate.org/eng/survey-dashboard/ev; Daniel Boston and Alyssa Werthman, "Plug-in Vehicle Behaviors"; "New Car Buyer Demographics 2020 (Updated)"

28 Electric Power Research Institute, Inc., *Plug-In Electric Vehicle Multi-State Market and Charging Survey*, February 26, 2016, available at https://www.epri.com/research/products/000000003002007495; Deloitte Consulting LLP, *Gaining Traction*; Christopher Butler, "Electric Vehicle Prices Finally in Reach of Millennial, Gen Z Car Buyers"

29 Electric Power Research Institute, Inc., *Plug-In Electric Vehicle Multi-State Market and Charging Survey*, February 26, 2016, available at https://www.epri.com/research/products/000000003002007495. Deloitte Consulting LLP, *Gaining Traction*

30 Deloitte Consulting LLP, *Gaining Traction*; Mark Kane, "Annual Electric Miles Traveled Varies Widely For 8 Plug-In Electric Cars," *InsideEVs*, May 16, 2015, https://insideevs.com/news/325893/annual-electric-miles-traveled-varies-widely-for-8-plug-in-electric-cars/.

31 Deloitte Consulting LLP, *Gaining Traction*; Mark Kane, "Annual Electric Miles Traveled Varies Widely For 8 Plug-In Electric Cars"; Ellen Edmonds, "AAA: Owning an Electric Vehicle is the Cure for Most Consumer Concerns"

32 Ellen Edmonds, "AAA: Owning an Electric Vehicle is the Cure for Most Consumer Concerns"

33 Ricardo research

34 Annie Palmer, "Amazon Debuts Electric Delivery Vans Created with Rivian," CNBC, October 8, 2020, updated October 8, 2020, https://www.cnbc.com/2020/10/08/amazon-new-electric-delivery-vans-created-with-rivian-unveiled.html.

FIGURE 16: EXPECTED EVOLUTION OF KEY EV BUYER DEMOGRAPHICS (2021-2030)

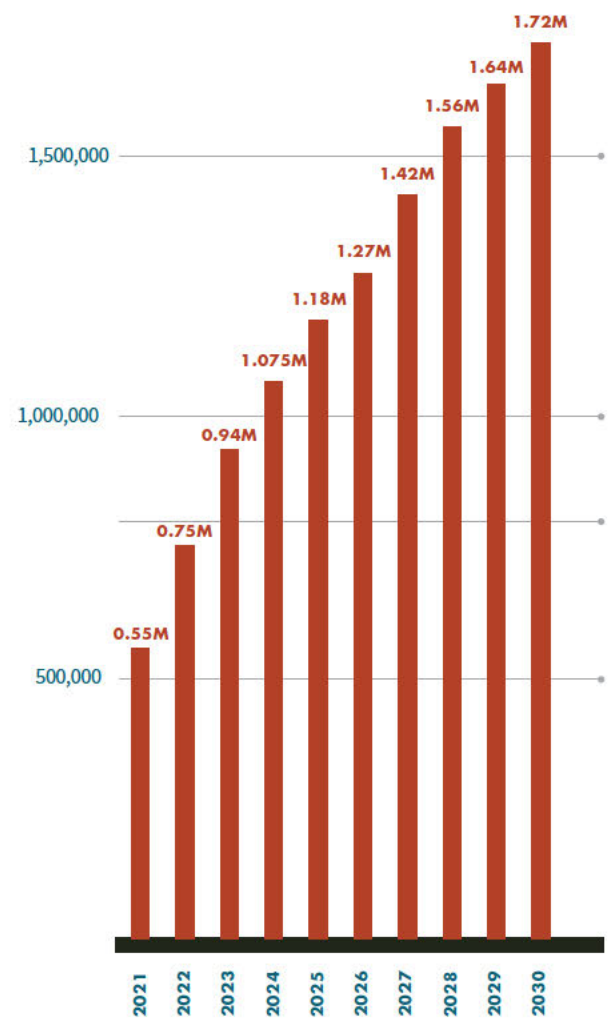
	2021	2025	2030
AGE	The average age is expected to normalize with the broader new-vehicle buyer trend.		
AVERAGE INCOME	Average income bracket is expected to drop down from the current bracket as EVs become more affordable.		
RESIDENCE	Number of EV drivers with no provision to charge at home is expected to increase as availability of public charging points increases along with the range of vehicles.		
MILEAGE	Driving pattern is expected to be similar to the way ICE vehicles are driven.		
GENDER	Gender distribution is expected to be more balanced with the launch of new vehicles in various segments with better range estimators.		

ANTICIPATED EVOLUTION OF EV BUYER DEMOGRAPHICS AND BEHAVIOR OVER THE NEXT 10 YEARS

BEV production is expected to steadily grow within the next decade. At some point, BEVs are expected to reach price parity with ICE vehicles (Figure 15).

Companies such as Volkswagen and Volvo expect to generate at least 40% of their sales from EVs by 2025; most other auto OEMs are expected to follow this trend.[35] By 2030, up to 40% of all new car sales could be EVs.[36] Given that the number of available EV segments is expected to broaden, the cost of owning an EV is forecast to be on par with a conventional vehicle, and charging infrastructure is estimated to grow to meet the demand,[37] the EV buyer demographic could normalize with the new car buyer over the next 10 years (Figure 16).

FIGURE 15: EXPECTED BEV PRODUCTION IN THE U.S. (2021-2030)



35 Tim Levin, "All the Things Carmakers Say They'll Accomplish with Their Future Electric Vehicles Between Now and 2030," *Business Insider*, January 28, 2020, https://www.businessinsider.com/promises-carmakers-have-made-about-their-future-electric-vehicles-2020-1.

36 McKerracher et al, *Electric Vehicle Outlook 2020*; U.S. Drive, *Summary Report on EVs at Scale and the U.S. Electric Power System*, November 2019, https://www.energy.gov/sites/prod/files/2019/12/f69/GITT%20ISATT%20EVs%20at%20Scale%20Grid%20Summary%20Report%20FINAL%20Nov2019.pdf.

37 Hao Wu, Genevieve Alberts, James Hooper, and Bryn Walton, *New Market. New Entrants. New Challenges. Battery Electric Vehicles* (London, UK: Deloitte LLP, 2019), https://www2.deloitte.com/content/dam/Deloitte/uk/Documents/manufacturing/deloitte-uk-battery-electric-vehicles.pdf.

According to a survey conducted by Volvo, more than half of respondents said they are likely to purchase an EV if the price is the same as an ICE vehicle.[38] The industry expectation that EV to ICE price parity may be realized in the coming decade would mean that EVs could be affordable to a broader consumer base.

The EV fleet is expected to grow in the upcoming years, primarily driven by state mandates. California and 27 other states have hybrid or EV fleet requirements, acquisition goals, or a stated preference for purchasing hybrid or EVs to be used in the state's fleet.

This will increase the probability of buyers with an annual household income of less than $100,000 to consider an EV for their next vehicle, thus pushing the average EV owner income bracket down from where it currently sits.

Bloomberg New Energy Finance predicts the ratio of EVs to public charging points is expected to reach 40-50 EVs per public charging point by 2040,[39] and as hardware costs fall and technology is commoditized, Wood Mackenzie predicts that there could be as many as 1.2 million public charging points in North America by 2030.[40] This increase in availability of public chargers could help potential consumers without access to a charger at home consider buying an EV.

Potential owners are inclined to purchase a BEV if it delivers a range of approximately 320 miles.[41] Given that Americans drive an average of 260 miles a week, [42] potential BEV buyers expect to get at least a week of driving range on a single charge. Many vehicles today offer more than 200 miles of range,[43] and the trend has been constant growth in BEV range. BEVs are expected to be driven like liquid-fuel-powered vehicles today, so the driving distance on a BEV is expected to be on par with the overall trend.

There appears to be a balanced distribution between the two genders in purchases of SUVs and sedans, however, the average EV customer is predominantly male.[44] According to a study by the University of California, Davis, amongst other reasons, female EV early adopters largely distrusted the range estimator.[45] There could be more female EV drivers when newer technology enables more accurate range predictors and perhaps better range as well.

The EV fleet is expected to grow in the upcoming years, primarily driven by state mandates. California and 27 other states have hybrid or EV fleet requirements, acquisition goals, or a stated preference for purchasing hybrid or EVs to be used in the state's fleet.[46] For example, California's 2020 mandate requiring 5-9% of 2024 model year trucks, based on class, to be ZEVs is expected to expand to have 30-50% of trucks to be ZEVs by 2030 and 100% where feasible by 2045.[47]

38 Volvo Car USA, *The State of Electric Vehicles in America*, February 26, 2019, https://www.media.volvocars.com/us/en-us/media/documentfile/249123/volvo-reports-the-state-of-electric-vehicles-in-america.

39 McKerracher et al., *Electric Vehicle Outlook 2020*

40 Jason Deign, "Up to 40 Million EV Charging Points Forecast Worldwide by 2030," *Green Tech Media*, August 9, 2018, https://www.greentechmedia.com/articles/read/electric-vehicle-charging-points-40-million-gtm.

41 Castrol, *Accelerating the EVolution: The Tipping Points to Mainstream Electric Vehicle Adoption*, 2020, https://www.castrol.com/content/dam/castrol/master-site/en/global/home/technology-and-innovation/electric-vehicle-adoption/accelerating_the_evolution_study.pdf.

42 "Average Annual Miles per Driver by Age Group," Federal Highway Administration, U.S. Department of Transportation, March 29, 2018, accessed October 15, 2020, available at https://www.fhwa.dot.gov/ohim/onh00/bar8.htm.

43 Dave Vanderwerp, "EV Range: Everything You Need to Know," *Car and Driver*, May 22, 2020, https://www.caranddriver.com/shopping-advice/a32603216/ev-range-explained/.

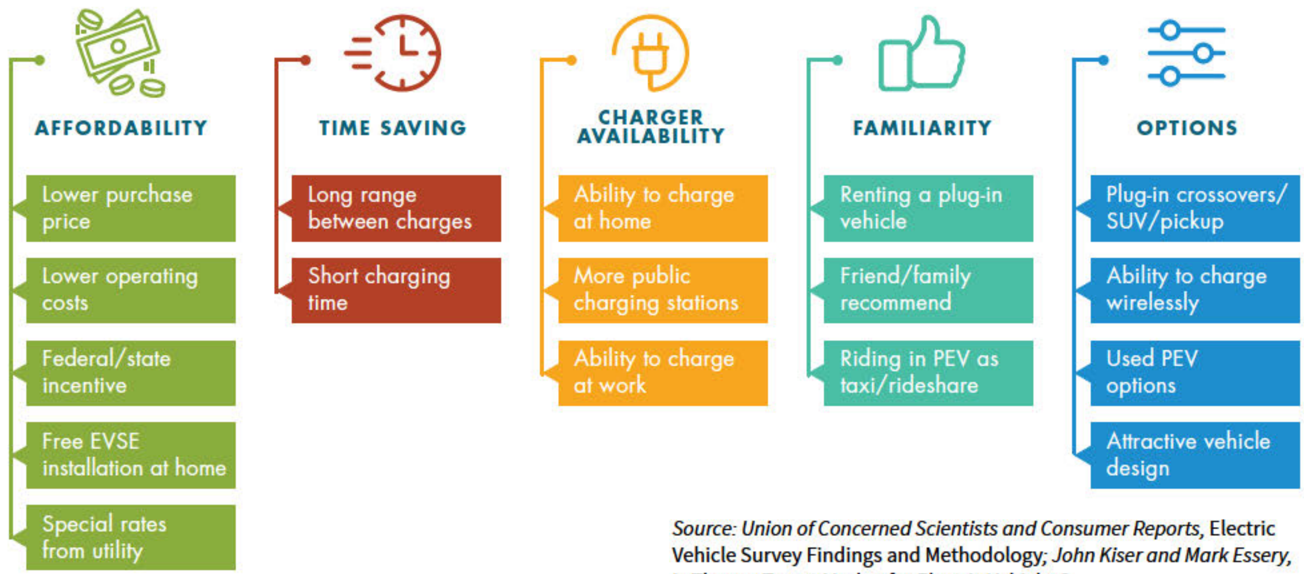
44 "New Car Buyer Demographics 2020 (Updated)"

45 Nicolette Caperello, Jennifer TyreeHageman, and Ken Kurani, "Engendering the Future of Electric Vehicles: Conversations with Men and Women" (presentation, Women's Issues in Transportation 5th International Conference, Paris, France, April 14-16, 2014) available at https://phev.ucdavis.edu/wp-content/uploads/2017/08/2014-UCD-ITS-RP-14-101.pdf.

46 Kristy Hartman and Emily Dowd, "State Efforts to Promote Hybrid and Electric Vehicles," National Conference of State Legislatures, September 26, 2017, https://www.ncsl.org/research/energy/state-electric-vehicle-incentives-state-chart.aspx.

47 David Shepardson and Nichola Groom, "California Passes Landmark Mandate for Zero Emission Trucks," Reuters, June 25, 2020, https://ca.reuters.com/article/idUSKBN23W31N.

FIGURE 17: FACTORS INFLUENCING LIKELINESS OF PEV PURCHASE (2017-2019)



Source: Union of Concerned Scientists and Consumer Reports, Electric Vehicle Survey Findings and Methodology; *John Kiser and Mark Essery,* Is There a Target Market for Electric Vehicles?

DEMOGRAPHIC CHARACTERISTICS AND THEIR RELATIONSHIP WITH EV OWNERSHIP AND BEHAVIOR

Currently, EVs are predominantly sedans or hatchbacks, which may not cater to the requirement of SUV, truck, and minivan drivers. In a 2019 study, the Union of Concerned Scientists (UCS) and Consumer Reports reported a strong consensus (72%) that PEVs should be produced in other forms,[48] so they may address the requirements of drivers of these vehicles.

In the same study, approximately half of all prospective EV buyers reported a belief that the federal government should invest money to help consumers buy PEVs. In addition, this belief is more prevalent in people of color (62% people of color versus 53% of all new car buyers).[49]

Another key theme is that younger people between the age of 25 and 34 may not be able to afford EVs due to factors such as student debt, wage stagnation, and lack of access to home charging or at-home parking. Some report using public transportation to be more practical than owning a car.[50]

PEV buyers appear to value affordability by means of a lower purchase price, lower operating costs, and federal and/or state support, amongst others (Figure 17).[51] They expect a PEV to be time-saving by charging quickly and having a long range. Charger availability at home and in public places appears important to prospective PEV buyers. Some of those surveyed feel that familiarity with the technology could encourage a purchase,[52] such as while renting a PEV and riding in a PEV ride-share or taxi. Potential buyers value choices in form and attractive vehicle design, amongst other factors, that could help them decide to purchase an EV.

48 Union of Concerned Scientists and Consumer Reports, *Electric Vehicle Survey Findings and Methodology*, July 2019, https://advocacy.consumerreports.org/wp-content/uploads/2019/07/ConsumerReports-UnionofConcernedScientists-2019-EV_Survey-7.17.19.pdf.

49 Union of Concerned Scientists and Consumer Reports, *Electric Vehicle Survey Findings and Methodology*

50 Christopher Butler, "Electric Vehicle Prices Finally in Reach of Millennial, Gen Z Car Buyers"

51 Union of Concerned Scientists and Consumer Reports, *Electric Vehicle Survey Findings and Methodology*; John Kiser and Mark Essery, *Is There a Target Market for Electric Vehicles?*, Ipsos, March 27, 2017, https://www.ipsos.com/sites/default/files/2017-04/ipsos-marketing-target-market-electric-vehicles.PD__0.pdf.

52 Union of Concerned Scientists and Consumer Reports, *Electric Vehicle Survey Findings and Methodology*

Decision making for adoption of EVs in commercial fleet applications is deeply rooted in viable business case and the ability to meet operational requirements. Hence, TCO and the payback period are key metrics considered by fleets, which are impacted by EV price, cost of infrastructure, operational cost savings, and residual value at the end of the vehicle's primary usage. Vehicle uptime, duty cycle, range, and payload requirements are other major factors that fleets take into consideration. EVs have penetrated several commercial vehicle on-highway and off-highway applications, such as transit buses, school buses, medium-duty delivery vans, yard trucks, forklifts, and heavy-duty on-highway trucks. However, currently commercial EVs are predominantly used for local operations, often involving stop-and-go duty cycles, where the vehicles return to base and rely on private charging infrastructure owned and operated by the fleet.[53]

DIFFERENCE IN TRIPS TAKEN IN EVS VERSUS LIQUID-FUEL VEHICLES

Early adopters found that limited battery range and lack of widespread availability of public chargers made longer trips more difficult in EVs. According to an AAA study, the average EV owner drives 39 miles a day.[54] This is slightly more than the national average of all vehicles, which is between 20-35 miles a day.[55] In general, more miles are driven today in an EV than in a conventional liquid-fueled vehicle, and drivers have started treating EVs like they would treat a conventional liquid-fueled vehicle. This is different from the situation a few years ago when the average number of miles driven in an EV had been roughly 15 miles a day.[56] This has been largely attributed to the increased range on EVs and availability of EV chargers, instilling confidence in drivers to drive longer miles, especially because operational expense for EVs is lower than that for gasoline vehicles.

To compare this difference in operational expense, in 2019, the U.S. national average price of gas was $2.5 per gallon.[57] The average fuel economy of a gas vehicle (average of short wheelbase light vehicle in 2019) is 24.1 mpg.[58] Based on the above, one mile costs 9.6 on gas. The average cost of retail residential electricity was 13.04 per kWh in 2019,[59] and the average fuel efficiency of a BEV is 32.63 kWh per 100 miles,[60] or 0.3263 kWh per mile. This implies one mile on electricity costs 4.25, which is roughly less than half of the cost to travel in a gas-powered vehicle.

Many states allow PEVs to use high-occupancy vehicle, or HOV, lanes, cutting drivers' commute times by a significant portion and helping them make a statement about their "tech-savvy-ness" or their environmental consciousness. This gives drivers more reasons to drive a PEV, especially when they have more than one vehicle in their household.

One major difference in EV driving behavior is that long trips are mostly planned with charging locations in mind, as opposed to a conventional vehicle's ability to re-fuel at almost any gas station, which far outnumber the number of available charging stations.

53 Ricardo research

54 Ellen Edmonds, "AAA: Owning an Electric Vehicle is the Cure for Most Consumer Concerns"

55 N. McGuckin and A. Fucci, *Summary of Travel Trends: 2017 National Household Travel Survey*; Daniel Boston and Alyssa Werthman, "Plug-in Vehicle Behaviors"

56 Deloitte Consulting LLP, *Gaining Traction*

57 "Gasoline and Diesel Fuel Update," Petroleum & Other Liquids, U.S. Energy Information Administration, accessed October 23, 2020, available at https://www.eia.gov/petroleum/gasdiesel/.

58 "Table 4-23: Average Fuel Efficiency of U.S. Light Duty Vehicles," Bureau of Transportation Statistics, https://www.bts.gov/content/average-fuel-efficiency-us-light-duty-vehicles.

59 "Average Retail Price of Electricity, United States, Annual," Electricity Data Browser, U.S. Energy Information Administration, available at https://www.eia.gov/electricity/data/browser/#/topic/7?agg=2,0,1&geo=g&freq=A&start=2001&end=2019&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0 (data accessed for year 2019).

60 "New All-Electric Vehicles," Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy, accessed October 16, 2020, https://www.fueleconomy.gov/feg/PowerSearch.do?action=noform&path=3&year1=2019&year2=2021&vtype=Electric&srchtyp=newAfv&tabView=0&pageno=1&sortBy=Comb&rowLimit=10 (fuel efficiency of all current BEVs were averaged).

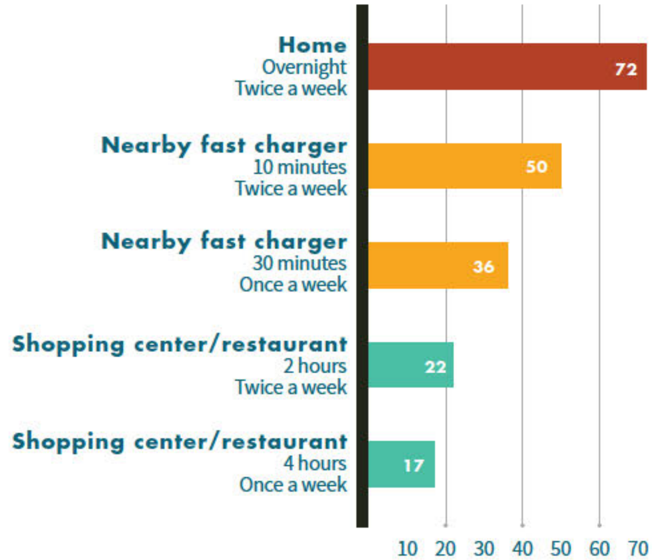
WHEN AND WHERE DOES THE CUSTOMER RECHARGE?

EV DRIVERS' CHARGING FREQUENCY

As the battery range of vehicles increases with every new model year, the confidence among EV owners is increasing, which is noted in the downward trend of charging frequency (Figure 18).[61] The average EV owner driving a 2016 or 2017 model year vehicle charged approximately once a day as opposed to EV drivers with vehicles of a 2011 model year that required to be recharged approximately twice a day (43 times a month). 2021 model year vehicles are predicted to not be very different from 2016 and 2017 model year vehicles and are expected to being charged roughly once a day. This trend, however, could see a slight rise as the number of public chargers increases. People are likely to plug in even when their EV has enough charge to complete the trip because of factors such as availability, convenience, and value (see "EV Drivers' Preferred Recharge Location").

The UCS and Consumer Reports found that most prospective PEV buyers would prefer to charge twice a week, overnight, at home (Figure 19).[62] They also found that prospective EV buyers who are people of color are more likely to find charging options outside the home to be more convenient, compared to all prospective car buyers combined.[63]

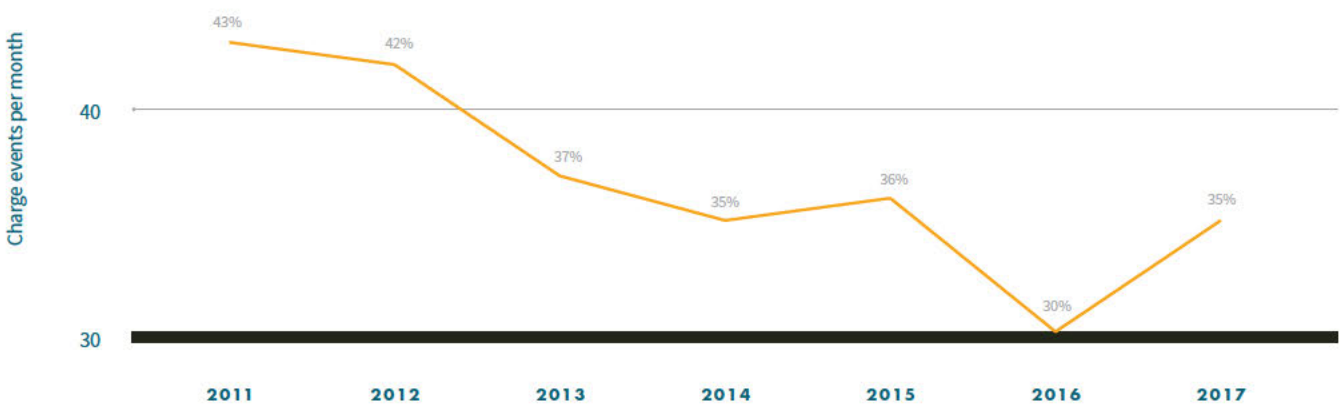
FIGURE 19: CHARGING OPTIONS PERCEIVED TO BE MOST CONVENIENT BY PROSPECTIVE PEV BUYERS (2017)



Note: Percentage represents proportion of respondents rating option as "completely convenient" or "very convenient"

Source: Union of Concerned Scientists and Consumer Reports, Electric Vehicle Survey Findings and Methodology

FIGURE 18: AVERAGE RECHARGE EVENTS PER MONTH BY MODEL YEAR



Note: Data includes U.S. and Canada

61 Eric Schmidt, "The Key to Increasing EV Adoption Is Hidden in EV Driving and Charging Data," FleetCarma, January 24, 2018, available at https://www.fleetcarma.com/key-increasing-ev-adoption-hidden-ev-driving-charging-data/.

62 Union of Concerned Scientists and Consumer Reports, *Electric Vehicle Survey Findings and Methodology*

63 Union of Concerned Scientists and Consumer Reports, *Electric Vehicle Survey Findings and Methodology*

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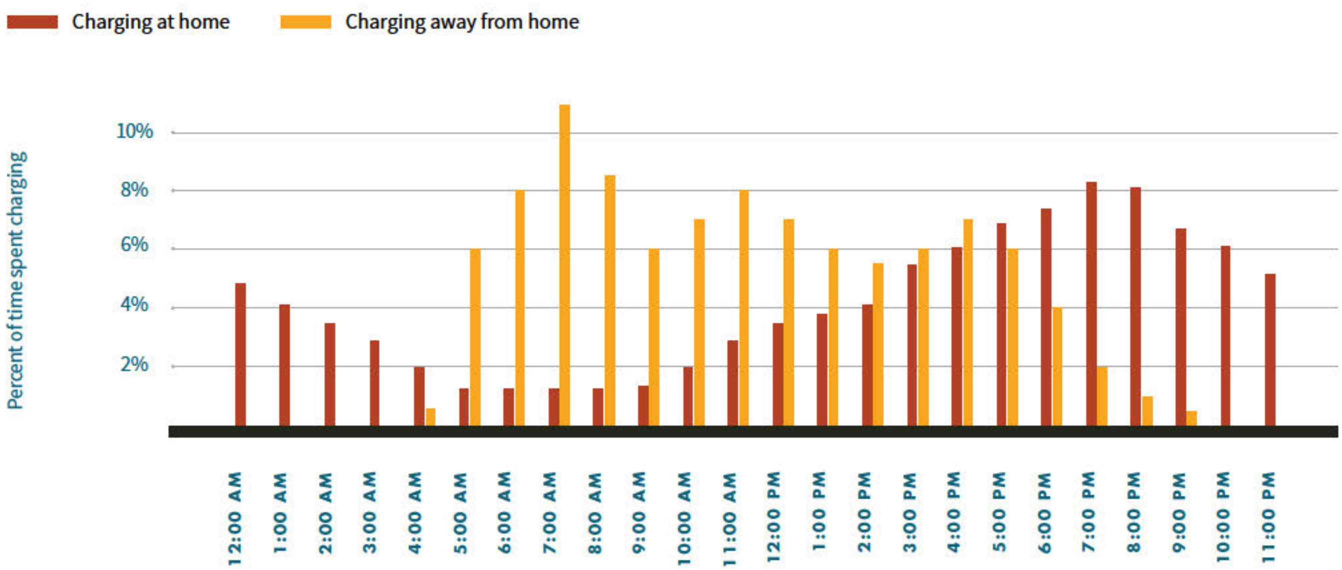
FIGURE 20: ESTIMATE: PERCENTAGE TIME SPENT CHARGING AT A GIVEN POINT IN TIME DURING THE DAY (2017)



Note: Away includes charging at work and at public charging stations

Source: American Public Power Association, A Public Power Guide to Understanding the U.S. Plug-in Electric Vehicle Market

The American Public Power Association in their 2017 study predicted that uncontrolled, aggregate EV charging could have a vehicle recharging profile as depicted in Figure 20.[64] They suggest that to avoid rising EV charging rates, utilities may need to incentivize consumers to charge in non-peak periods.[65]

EV commercial fleet customers operate in a hub-and-spoke network and tend to exclusively recharge their vehicles at their base. Their charging schedule largely depends on their operation shifts. Vehicles operating day shift, such as transit buses, school buses, and delivery trucks, are typically plugged in at the end of the shift for overnight charging. However, opportunity charging has also been observed in certain applications such as yard facilities and transit bus routes, particularly where the vehicle operation tends to be very busy and the window for charging is narrow.[66]

64 American Public Power Association, *A Public Power Guide to Understanding the U.S. Plug-in Electric Vehicle Market*, 2017, available at https://www.amea.com/wp-content/uploads/2018/08/understanding_the_us_plug-in_electric_vehicle_market_2017_digital_final.pdf.

65 American Public Power Association, *A Public Power Guide to Understanding the U.S. Plug-in Electric Vehicle Market*

66 Ricardo research

EV DRIVERS' PREFERRED RECHARGE LOCATION

A few years ago, EV charging occurred 80% of the time at home, according to the U.S. Department of Energy's (DOE) Office of Energy Efficiency and Renewable Energy (Figure 21).[67] Among survey participants, 57% exclusively charged at home and 40% claimed to recharge at home and away in 2015.[68] In 2018, 67% of those surveyed charged either at home or at work and the remaining third of the participants charged elsewhere.[69]

The DOE, INL, and others conducted an EV Project study between 2011 and 2013 (Figure 22).[70] Charging events by site per week exhibit a large range; however, the median was around nine events per week. The most used parking lot charges were those located in downtown areas. Workplace charging and chargers located in multi-family complexes were also amongst the most used.

67 "Charging at Home," Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy, accessed on October 20, 2020, available at https://www.energy.gov/eere/electricvehicles/charging-home.

68 Electric Power Research Institute, Inc., *Plug-In Electric Vehicle Multi-State Market and Charging Survey*

69 Volvo Car USA, *The State of Electric Vehicles in America*

70 John Smart, "EV Charging Infrastructure Usage in Large-scale Charging Infrastructure Demonstrations: Public Charging Station Case Studies for ARB," (presentation, Plug-in Electric Vehicle Infrastructure Information Gathering Meeting, July 15, 2014), available at https://avt.inl.gov/sites/default/files/pdf/EVProj/EVInfrastructureUsageARBJul2014.pdf.

FIGURE 21: AVERAGE PEV CHARGING FREQUENCY BY LOCATION

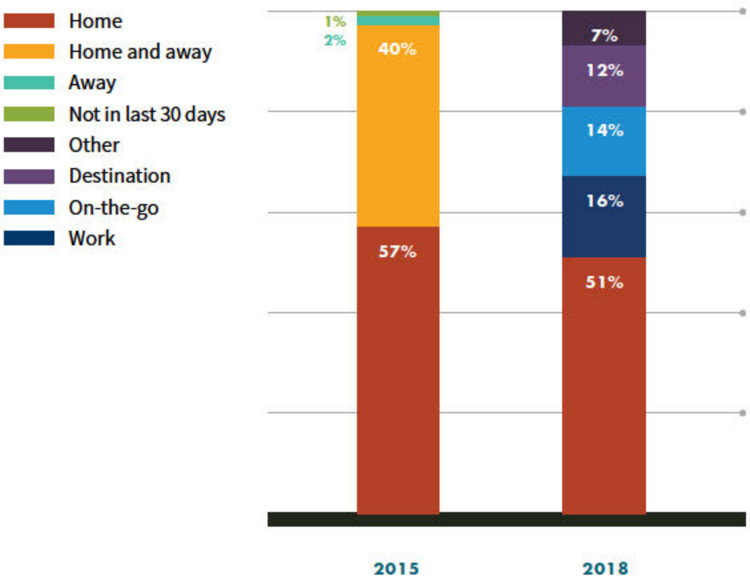
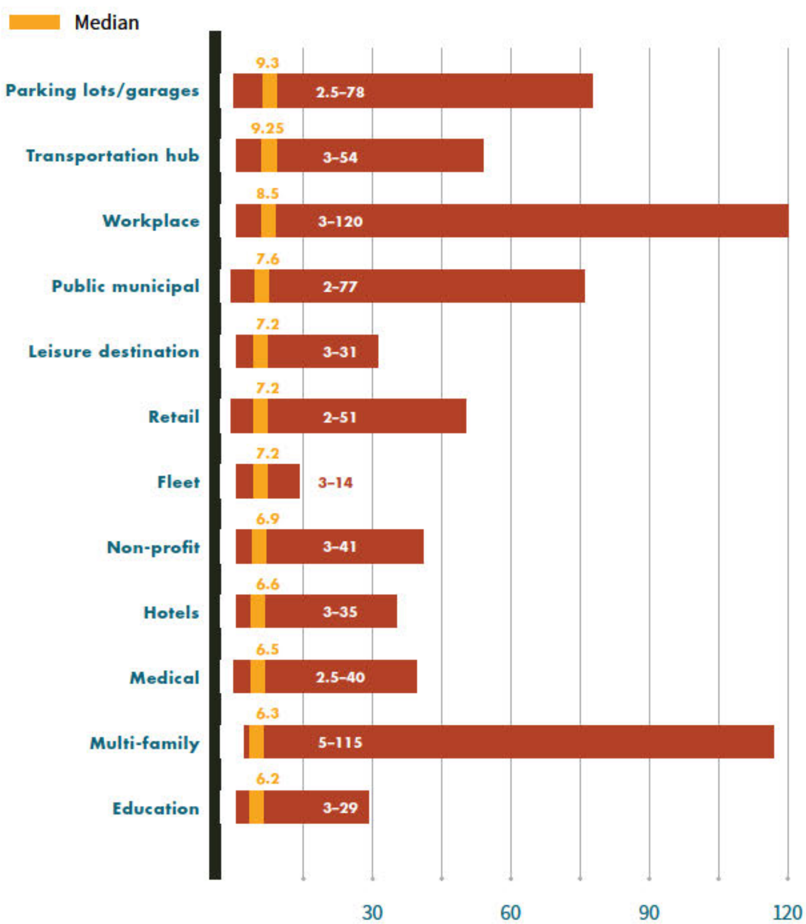


FIGURE 22: AVERAGE NUMBER OF CHARGING EVENTS PER SITE PER WEEK FOR LEVEL 2 EVSE (2012-2014)



Source: John Smart, "EV Charging Infrastructure Usage in Large-scale Charging Infrastructure Demonstrations: Public Charging Station Case Studies for ARB"

Although, the majority of recharging was done at home and/or at work, INL found that many DCFC that were open to the public experienced heavy usage by both inter-city and in-town traffic, and a relatively smaller number of Level 2 chargers saw constant high usage.[71] Public Level 2 chargers in locations where vehicles are parked for longer periods of time, such as shopping malls, airports, commuter lots, and downtown parking lots with easy access to a variety of venues, were amongst the ones that were most used during the period of study.[72] Since this study was conducted between 2011 and 2013, a similar study could be commissioned to understand current preferences.

EVs operated by commercial fleets are charged exclusively at their bases using private charging stations owned and operated by the fleets. However, availability of public charging stations in the future can help alleviate the financial burden and responsibilities of installing charging infrastructure to some extent; some fleets may rely completely on public charging stations while others may consider those as an option for extending the range if the battery state-of-charge is low during regular operations. However, this is going to require the industry to use standard charging protocol and the network of public charging stations to be reliable and available. Private charging stations are still expected to be predominant charging locations amongst commercial fleets, particularly the early adopter large fleets. But adoption of EVs in mass market and smaller commercial fleets may spur the growth of public charging station networks.[73]

Amazon plans to have 10,000 electric delivery vehicles by 2022 and 100,000 by 2030 to help meet its goal of achieving carbon neutrality by 2045 as part of its Climate Pledge.[74] In order to meet this goal, Amazon would need to switch their middle-mile transport fleet to EVs as well. Amazon and their delivery partners currently install charging stations at home base for their last-mile delivery fleet, but to meet the extended range requirements for middle-mile delivery, they may need to use public infrastructure on highways.[75]

71 John Galloway Smart and Shawn Douglas Salisbury, *Plugged In: How Americans Charge Their Electric Vehicles* (Idaho Falls, ID: Idaho National Laboratory on behalf of the U.S. Department of Energy Office of Scientific and Technical Information, January 7, 2015), https://doi.org/10.2172/1369632.

72 John Galloway Smart and Shawn Douglas Salisbury, *Plugged In: How Americans Charge Their Electric Vehicles*

73 Ricardo research

74 Mary Meisenzahl, "Amazon Just Revealed Its First Electric Delivery Van of a Planned 100,000-Strong EV Fleet — See How It Was Designed," *Business Insider*, February 3, 2021, https://www.businessinsider.com/amazon-creating-fleet-of-electric-delivery-vehicles-rivian-2020-2.

75 Ricardo research

Many DCFC that were open to the public experienced heavy usage by both inter-city and in-town traffic, even though most recharging was done at home and/or at work.

In compairison, a relatively smaller number of Level 2 chargers saw constant high usage.[71]

FIGURE 23: FACTORS INFLUENCING EV DRIVERS' DECISION TO RECHARGE AT PUBLIC CHARGER VERSES HOME OR WORK

EV drivers tend to mostly recharge at home and/or work. A few factors that prompt using public chargers include the following (Figure 23):

1) **Nonavailability:** Drivers who do not have access to a charger at home or at work must recharge at public charging stations.[76]

2) **Running out of range:** Drivers who exceed the range of the vehicle battery on any given day may need to visit a public fast charging station.[77]

3) **Accessibility:** Charging stations' availability at places where drivers would park anyway, such as shopping malls, restaurants, grocery stores, etc., where it takes only a few seconds to plug in, encourages drivers to use a public charger.[78]

4) **Value:** A driver may choose the value of using a public charger that is free of cost.[79]

5) **Convenience:** EV chargers are usually nearer to the entrance of public amenities, thus drivers receive preferential treatment.[80]

6) **Forgetting to charge at home:** Drivers who forget to charge their car at home might have to rely on a public charging station to maintain daily travel plans.[81]

FACTORS THAT INFLUENCE A RECHARGE OCCASION

Charging occurs predominantly either at home or at work and typically overnight, similar to when users recharge their cellphones when there is a guaranteed downtime. Some drivers plug in at workplaces when chargers are available and free of cost. Drivers may plug in to public chargers when the charger is available for free to get more value by virtue of free electricity, to access priority parking in an otherwise crowded parking lot, and when the charger is available at locations where they would have parked anyway. Since most BEV drivers drive well within the battery range for most of their travel requirements, a public charger is only unavoidable while making trips longer than the battery range would permit.

Conventional vehicle drivers, on the other hand tend to base their refueling preference on time, necessity, and cost, amongst other factors. According to the National Motorist Association, citing an Esurance survey, 32% of drivers wait until their gas light turns on to fill up their tank, although drivers over age 55 tend to fill up while their tank is still half full. Participants claim to put off getting gas because they

76 Hauke Engel, Russell Hensley, Stefan Knupfer, and Shivika Sahdev, "Charging Ahead: Electric-Vehicle Infrastructure Demand," McKinsey and Company, August 8, 2018, https://www.mckinsey.com/industries/automotive-and-assembly/our-insights/charging-ahead-electric-vehicle-infrastructure-demand.

77 Engel et al., "Charging Ahead: Electric-Vehicle Infrastructure Demand"

78 Mal Skowron, "Smart EV Charging Habits," *The Energy Consumer Bulletin*, Green Energy Consumers Alliance, May 8, 2020, https://blog.greenenergyconsumers.org/blog/smart-ev-charging-habits.

79 Electric Power Research Institute, Inc., *Plug-In Electric Vehicle Multi-State Market and Charging Survey*

80 New York State Energy Research and Development Authority and Transportation and Climate Initiative, *Siting and Design Guidelines for Electric Vehicle Supply Equipment*, November 2012, https://www.transportationandclimate.org/sites/default/files/EV_Siting_and_Design_Guidelines.pdf.

81 Hauke Engel et al., "Charging Ahead: Electric-Vehicle Infrastructure Demand"

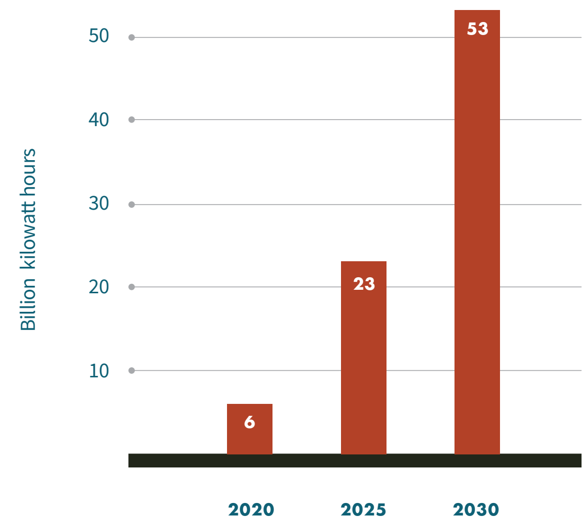
do not have enough funds for a full tank (30%) or they are too busy to fill up and perceive getting gas as inconvenient (26%).[82]

NACS: The Association for Convenience & Fuel Retailing found that nearly 40 million Americans fill up every day, and 59% of respondents said that price dominates where they purchase fuel, but quality of fuel, food, and employees aid their decision.[83] They also found that 33% of consumers prefer to purchase fuel during the evening rush as opposed to the morning rush, when 22% of the respondents fueled up. Many drivers age 65 or more tend to fill up midday while most drivers who purchase gas in the morning are between the ages of 35 and 49.

CHARGING INFRASTRUCTURE REQUIREMENT

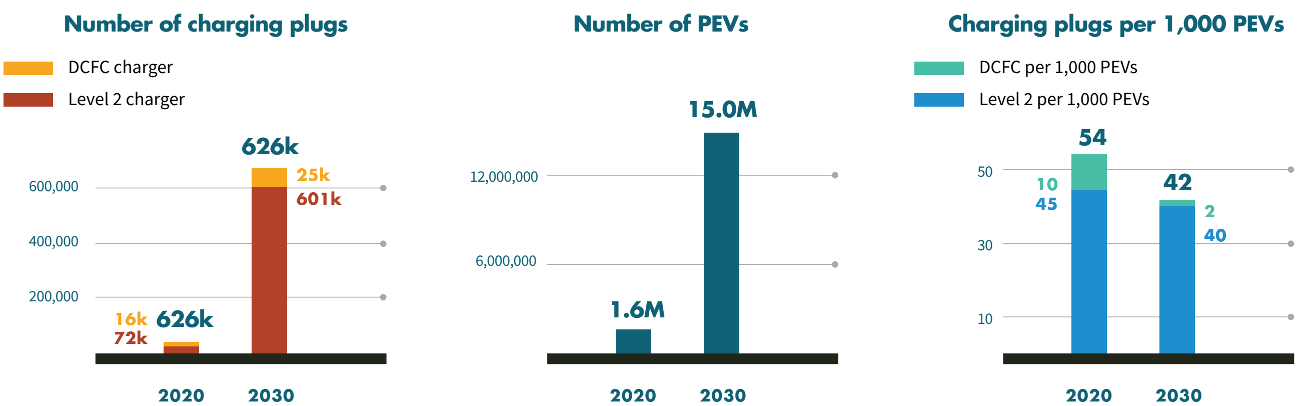
McKinsey predicts that the PEV-related energy demand would go up almost tenfold by 2030 (Figure 24).[84] This falls in line with the prediction that there could be between 12 and 15 million PEVs by 2030 — up by nearly 10 times of today's 1.6 million PEVs (Figure 25).[85]

FIGURE 24: CHARGING ENERGY DEMAND PREDICTION FOR PERSONAL EVS IN BILLION KILOWATT-HOURS



Note: Annual mileage is estimated at 18,095 km and battery efficiency estimated at approximately 20 kWh per 100 km.

FIGURE 25: CURRENT INFRASTRUCTURE AVAILABILITY AND 2030 FORECAST OF PUBLIC CHARGERS



Note: 2020 PEV numbers are estimated based on the assumption that all PEVs sold since 2010 are still in operation; 2020 data is accurate as of August 2020 and does not estimate PEV sales through the end of the year nor infrastructure developed through the end of the year.

82 Karlie Kramer, "When Do You Fill Up Your Gas Tank?," National Motorists Association, October 22, 2019, https://www.motorists.org/blog/when-do-you-fill-up-your-gas-tank/.

83 NACS, *Consumer Behavior at the Pump*, Consumer Insights series, March 2019, https://www.convenience.org/Topics/Fuels/Documents/How-Consumers-React-to-Gas-Prices.pdf.

84 Engel et al., "Charging Ahead: Electric-Vehicle Infrastructure Demand"

85 Eric Wood, Clément Rames, Matteo Muratori, Sesha Raghavan, and Marc Melaina, *National Plug-In Electric Vehicle Infrastructure Analysis* (U.S. Department of Energy Office of Energy Efficiency and Renewable Energy, September 2017) https://www.nrel.gov/docs/fy17osti/69031.pdf; "FOTW #1153, September 28, 2020: Cumulative Plug-In Vehicle Sales in the United States Reach 1.6 Million Units," U.S. Department of Energy Office of Energy Efficiency and Renewable Energy, September 28, 2020, https://www.energy.gov/eere/vehicles/articles/fotw-1153-september-28-2020-cumulative-plug-vehicle-sales-united-states-reach; Thibaut Abergel, Till Bunsen, Marine Gorner, Pierre Leduc, Sarbojit Pal, Leonardo Paoli, Seshadri Raghavan, et al. *Global EV Outlook 2020: Entering the Decade of Electric Drive?* (International Energy Agency, June 2020) https://webstore.iea.org/download/direct/3007.

Although approximately 70%-80% of charging takes place at home or at work,[86] EVs are expected to be driven like present-day ICE vehicles.[87] A study by Navigant Research estimates that 95 DCFC stations along major highway corridors would enable travel across the U.S. and that 408 DCFC stations would suffice to meet long-distance travel needs of EVs in the 100 largest metropolitan areas of the U.S.[88] Analysis by the National Renewable Energy Laboratory (NREL) in 2017 found that DCFC stations would be required to be spaced 70 miles apart on average to provide BEV drivers access across the U.S. interstate system. Their analysis further revealed that to dispel range anxiety concerns, BEV drivers in cities and towns must never be more than three miles from a DCFC, requiring 8,200 charging stations (25,000 plugs) across the U.S. for a 15 million PEV projection.[89]

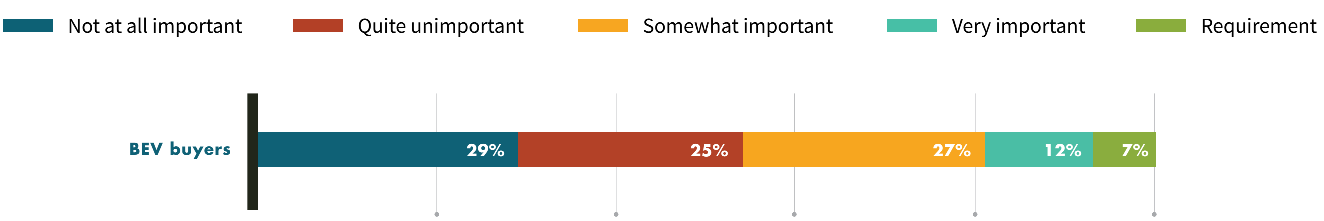
This number appears to be the bare minimum since automotive OEMs are already partnering with charging providers to install DCFC stations. As an example, General Motors alone in partnership with EVgo will add 2,700 DCFC stations by 2025.[90]

WHY DOES THE CUSTOMER CHOOSE A PARTICULAR PUBLIC RECHARGING FACILITY?

LEVEL 2 CHARGING AVAILABILITY'S INFLUENCE ON CONSUMER PERCEPTION OF AVAILABILITY, CAPACITY, AND CONVENIENCE COMPARED TO DCFC EQUIPMENT

In CleanTechnica's survey of current and potential EV drivers, 46% of respondents feel that DCFC is not "very important" and 54% felt it was "very important" or a "requirement"(Figure 26).[91] In a different study, CleanTechnica found that approximately 70% of BEV drivers used DCFC only a few times a year (Figure 27).[92] In the same study, approximately 42% of non-Tesla BEV drivers think the current EV charging network is "very adequate," and approximately 33% think it is "somewhat adequate."

FIGURE 26: IMPORTANCE OF DCFC WHEN BUYING A BEV (2016)



Note: Surveyed participants from the U.S. (approximately 75%), Canada (approximately 8%), and the U.K. and Australia (<10% combined)
Source: CleanTechnica, Electric Car Drivers: Desires, Demands, and Who They Are

86 "Charging at Home," Office of Energy Efficiency and Renewable Energy; Volvo Car USA, *The State of Electric Vehicles in America*

87 Eric Wood et al., *National Plug-In Electric Vehicle Infrastructure Analysis*

88 Navigant Research, "408 High-Power DC Charging Stations Would Meet Long-Distance Travel Needs for Battery Electric Vehicles in the Top 100 U.S. Metropolitan Areas," *Guidehouse Insights*, June 21, 2016, https://guidehouseinsights.com/news-and-views/408-highpower-dc-charging-stations-would-meet-longdistance-travel-needs-for-battery-electric-vehicle.

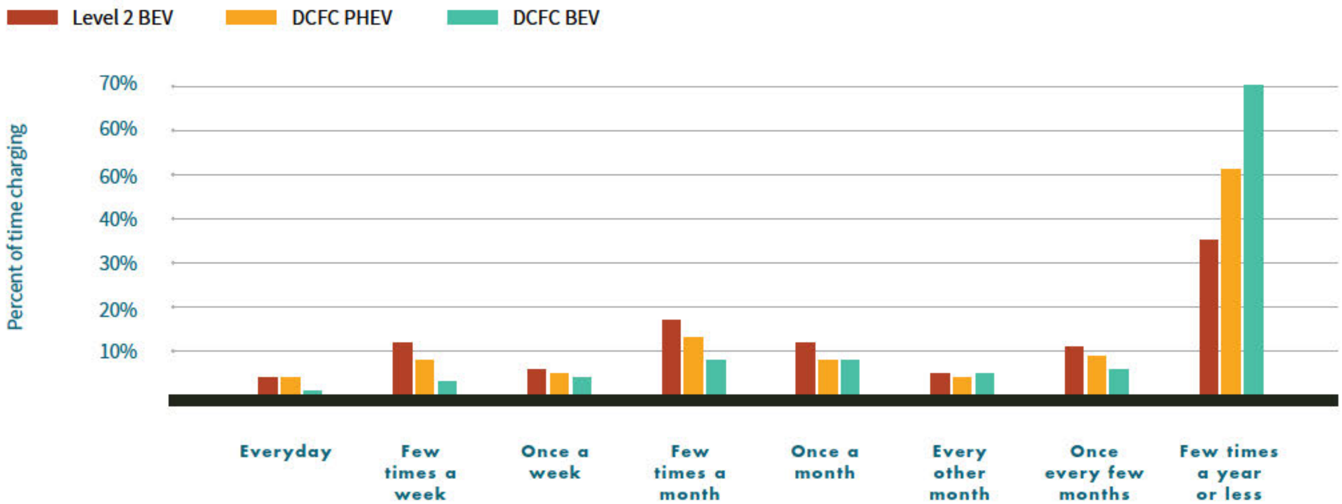
89 Eric Wood et al., *National Plug-In Electric Vehicle Infrastructure Analysis*

90 John Voelcker, "GM to Fund Expansion of EVgo Fast-Charging Network For Electric Cars," *Charged Electric Vehicles Magazine*, July 31, 2020, https://chargedevs.com/newswire/gm-to-fund-expansion-of-evgo-fast-charging-network-for-electric-cars/.

91 CleanTechnica, *Electric Cars: What Early Adopters and First Followers Want*, 2015, available at https://future.cleantechnica.com/reports/electric-cars-what-early-adopters-and-first-followers-want.

92 CleanTechnica, *Electric Car Drivers: Desires, Demands, and Who They Are*, 2016, available at https://cleantechnica.com/files/2017/05/Electric-Car-Drivers-Report-Surveys-CleanTechnica-Free-Report.pdf.

FIGURE 27: FREQUENCY OF PUBLIC CHARGER USAGE BY PERCENTAGE (NORTH AMERICAN NON-TESLA DRIVERS) (2017)

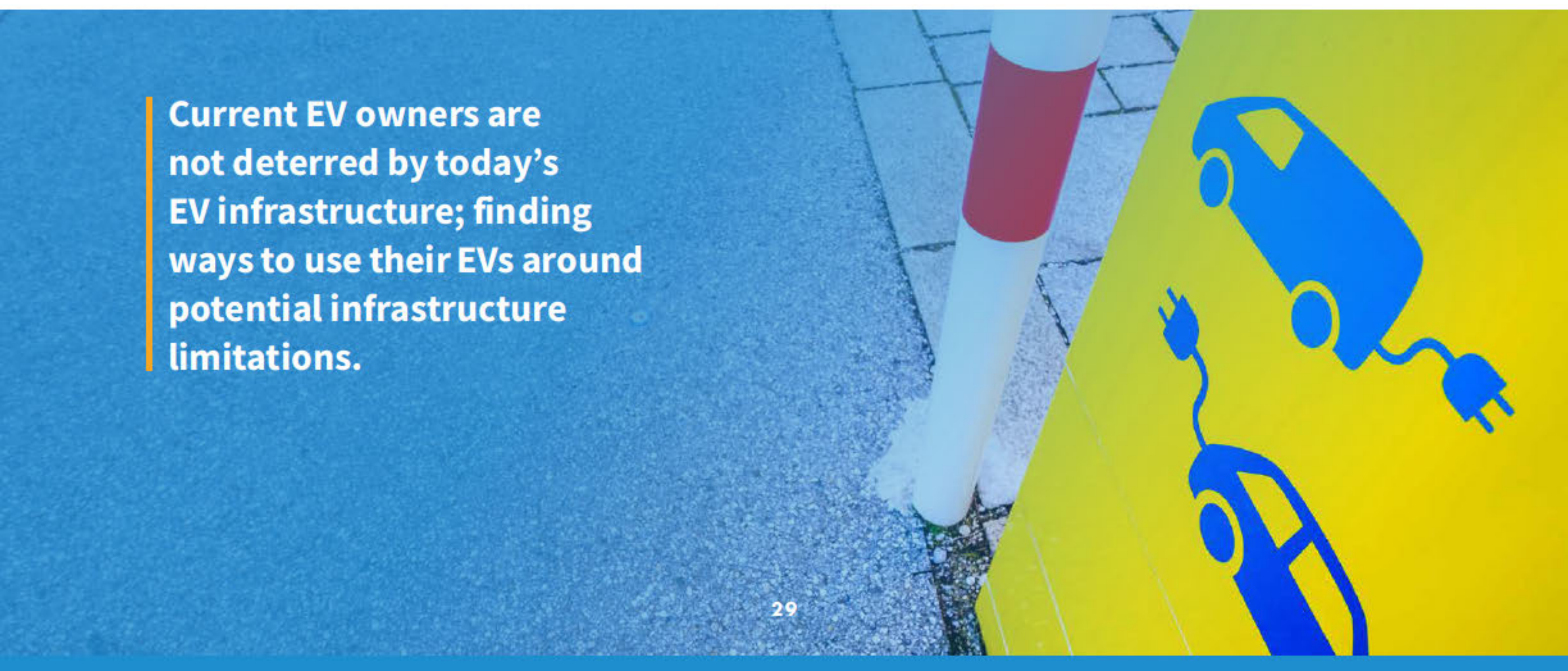


Source: CleanTechnica, Electric Car Drivers: Desires, Demands, and Who They Are

Tesla, as of August 2020, owned 8,509 Superchargers (equivalent to DCFCs) and 11,685 Destination Charging locations (equivalent to Level 2 chargers), which makes the Tesla network approximately 54% of all DCFCs in the U.S. and approximately 16% of all Level 2 chargers. Non-Tesla EV drivers currently have access to approximately 7,000 DCFCs and approximately 60,000 Level 2 chargers.[93]

These data points suggest that current EV owners are not deterred by today's EV infrastructure; rather, they have found ways to use EVs around potential infrastructure limitations. For mass adoption, it is important to understand the views of buyers who do not consider EVs today. This can be pursued with a targeted survey toward those individuals.

93 "FOTW #1153, September 28, 2020: Cumulative Plug-In Vehicle Sales in the United States Reach 1.6 Million Units"



INFLUENCE OF CHARGING EQUIPMENT BRAND[94]

EV drivers' selection of a particular brand of charger can be influenced by the following factors:

1) **Built-in equipment:** Vehicles like the Hyundai Ioniq and Chevrolet Bolt EV usually either have a ChargePoint or similar charge card in the glovebox of the vehicle when bought new.[95] Many drivers, since the charge card is already available, tend to use the corresponding brand of charging network. Tesla, with the charging application integrated into the infotainment system, allows for seamless operation within its network. Nissan Leafs ship with an EZ Card that allows the driver to use chargers operated by ChargePoint, Blink, Network from Car Charging Group, AeroVironment, and NRG EVgo.[96]

2) **Familiarity:** Charging network providers like ChargePoint and Blink also make home chargers.[97] When a consumer has one of them installed at home, familiarity with the home charger could bias their choice of a public charger used especially when they are new to owning EVs.

3) **Dependability:** Consumer Reports notes that some networks are more dependable than others and that chargers at newer stations can be out of service.[98]

4) **Availability:** ChargePoint has more than 35,000 Level 2 chargers in the U.S., which is just shy of the combined total of all other networks' Level 2 chargers combined.[99] However, networks are not uniformly distributed throughout the country. Hence, a customer's choice could sometimes be based on availability, rather than by choice. For example, in Alaska, out of the 39 available Level 2 plugs, only eight are operated by ChargePoint and 24 are non-networked.[100] So, an EV owner in Alaska might prefer signing up with ChargePoint to have access to eight chargers, which is more convenient than signing up individually with various standalone providers that operate each of the other chargers.

5) **Charging host:** A customer may prefer to use a particular charger network based on their needs and habits. For example, a customer who shops at a particular grocery store, where a charger of a certain network is installed, might choose to use that particular network for their charging needs because they go there anyway and plugging in would be an added convenience.

94 The topic discussed in this section of the report has limited public domain data, so inference is based on relevant knowledge and experience.

95 Jeannie Lam, "Everything You Need to Know About the Hyundai Ioniq Electric," ChargePoint, February 20, 2017, https://www.chargepoint.com/blog/everything-you-need-know-about-hyundai-ioniq-electric/.

96 Nissan North America, "Nissan Launches Programs to Make Leaf Charging Free and "EZ," news release, ChargePoint, April 2014, https://www.chargepoint.com/about/news/nissan-launches-programs-make-leaf-charging-free-and-ez/.

97 Gabe Shenhar and Jeff S. Bartlett, "How to Choose the Best Home Wall Charger for Your Electric Vehicle," *Consumer Reports*, September 30, 2020, https://www.consumerreports.org/hybrids-evs/how-to-choose-the-best-home-wall-charger-for-your-electric-vehicle/.

98 Jeff Plungis, "How the Electric Car Charging Network Is Expanding," *Consumer Reports*, November 12, 2019, https://www.consumerreports.org/hybrids-evs/electric-car-charging-network-is-expanding/.

99 "Alternative Fueling Station Locator," Alternate Fuels Data Center, Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy, accessed October 29, 2020, https://afdc.energy.gov/stations/#/analyze.

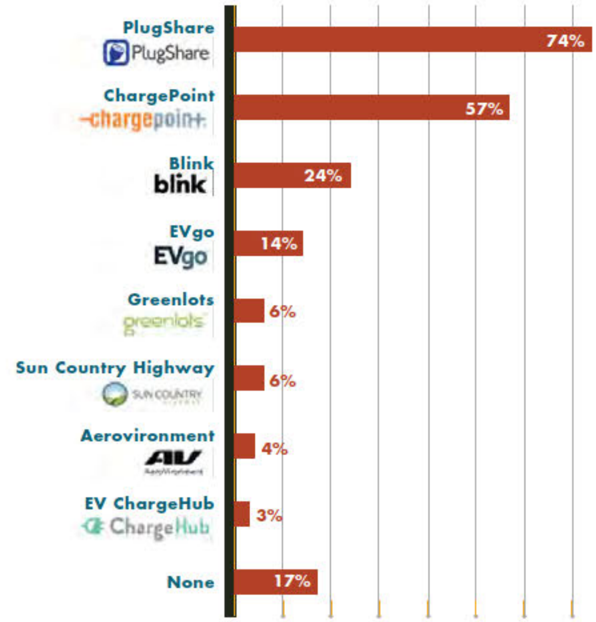
100 "Alternative Fueling Station Locator," Alternate Fuels Data Center

CleanTechnica found that PlugShare was the most popular app — it had been used by 74% of the participants (Figure 28).[101]

Various sources point to the fact that on average PEV drivers rely on public charging stations for only 20%-33% of their charging needs, and the remaining 67%-80% of charging happens at home or at work.[102] More than 80% of drivers use only three public locations or fewer for their charging needs away from home and work. Cumulatively, approximately 38% of all PEVs sold were Tesla vehicles before 2019,[103] and in 2019, 58% of all PEVs sold were Tesla vehicles. Tesla has their Superchargers network integrated onto the infotainment system, negating the need for an app. Based on this, it would be safe to assume that fewer than 5% of EV drivers use apps on a daily or frequent basis to locate charging stations. It is likely that EV owners download at least one of these apps, and app usage is likely to be more frequent when in a new location (Figure 29).[104]

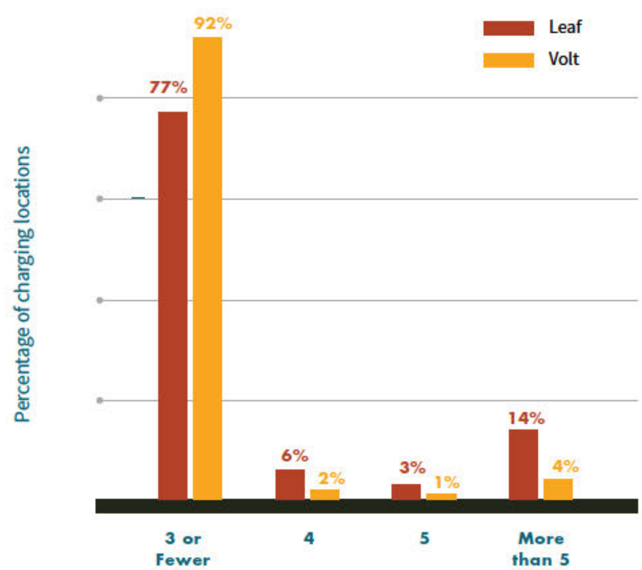
Going forward, OEMs are likely to provide similar attributes to Tesla's in-vehicle point-to-point trip-planning feature. As more owners use their EVs for long-distance travel, the need for trip planning and finding public charging will increase. However, use of such in-vehicle features as opposed to smartphone apps would depend on which method provides seamless ease of use. OEMs could also plan to integrate smart routing into their interface; with availability of data such as power output and vehicle state-of-charge, the in-car navigation system could optimize the route by planning a stop at a faster charging station to reduce overall trip time.

FIGURE 28: WEBSITES/APPS FOR NORTH AMERICAN EV OWNERS TO LOCATE EV CHARGING STATIONS (2017)



Source: CleanTechnica, Electric Cars: What Early Adopters and First Followers Want

FIGURE 29: NUMBER OF AWAY-FROM-HOME LOCATIONS WHERE DRIVERS DO MOST CHARGING (2011-2014)



Note: Data collected between 2011 and 2014

Source: John Galloway Smart and Shawn Douglas Salisbury, Plugged In: How Americans Charge Their Electric Vehicles

101 CleanTechnica, *Electric Cars: What Early Adopters and First Followers Want*

102 Volvo Car USA, *The State of Electric Vehicles in America*; "Charging at Home," Office of Energy Efficiency and Renewable Energy

103 "U.S. Plug-in Electric Vehicle Sales by Model" (chart), "Maps and Data — U.S. Plug-in Electric Vehicle Sales by Model" (webpage), Alternate Fuels Data Center, Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy, accessed October 10, 2020, https://afdc.energy.gov/data/10567.

104 John Galloway Smart and Shawn Douglas Salisbury, *Plugged In: How Americans Charge Their Electric Vehicles*

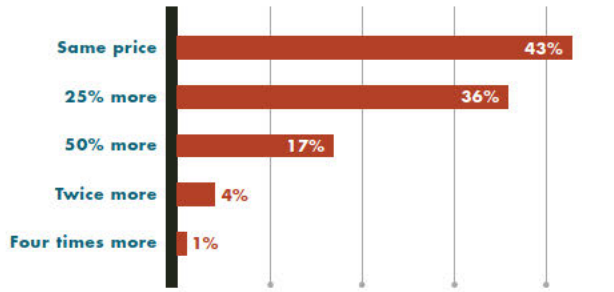
HOW DO CUSTOMERS INTERACT WITH CHARGING EQUIPMENT?

EV CONSUMERS' WILLINGNESS TO PAY FOR CHARGING SERVICES AND THE INFLUENCE OF PRICE IN THIS PERCEPTION

ESource, in their survey of current and potential PEV owners, found that 57% of respondents are willing to pay a premium to use a DCFC, and 22% of respondents are willing to pay a premium of 50% or more for access to a DCFC (Figure 30).[105] When asked to compare EV charging to paying for gas, 70% of respondents perceived that they pay the same or less to charge an EV as compared to buying gas (Figure 31).[106]

In this same study, ESource further found that 44% of PEV owners are willing to pay between $1-$2 per hour to use a public charger with an assumption that at-home charging is valued at $0.75 per hour (Figure 32).[107] The willingness is observed to steadily decline at rates greater than $2 per hour. Potential PEV owners, on the other hand, appear to be more price sensitive — their willingness to pay for public charging peaks at $1 per hour and declines at higher prices, and 12% of respondents claim that they would not use a public Level 2 charger.[108]

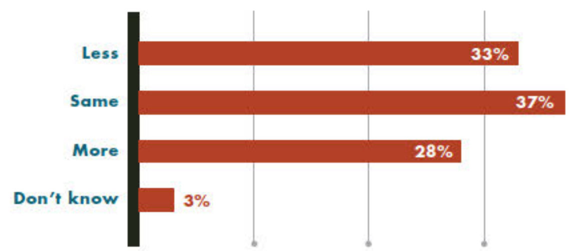
FIGURE 30: AMOUNT RESPONDENTS WOULD PAY FOR A DCFC COMPARED TO A LEVEL 2 CHARGER (2020)



Note: Data includes U.S. and Canada respondents who own or are considering owning a PEV

Source: Bill LeBlanc, "EV Charging and Pricing: What Are Consumers Willing To Pay?"

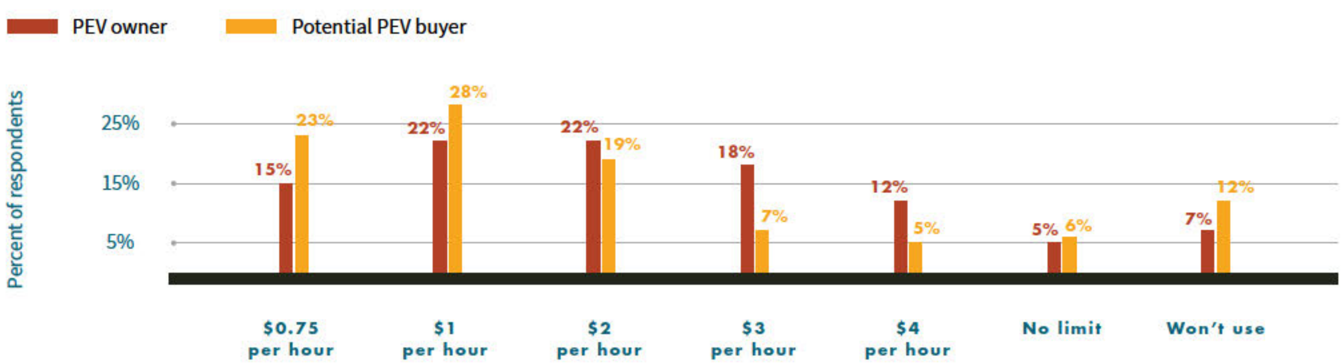
FIGURE 31: AMOUNT RESPONDENTS PERCEIVE THEY PAY TO CHARGE A PEV COMPARED TO BUYING GAS (2020)



Note: Data includes U.S. and Canada respondents who own a PEV

Source: Bill LeBlanc, "EV Charging and Pricing: What Are Consumers Willing To Pay?"

FIGURE 32: AMOUNT RESPONDENTS ARE WILLING TO PAY FOR PUBLIC LEVEL 2 CHARGING ASSUMING COST TO CHARGE AT HOME IS $0.75 PER HOUR (2020)



Note: Data includes U.S. and Canada respondents

Source: Bill LeBlanc, "EV Charging and Pricing: What Are Consumers Willing To Pay?"

105 Bill LeBlanc, "EV Charging and Pricing: What Are Consumers Willing To Pay?," *ESource*, September 1, 2020, https://www.esource.com/429201ebtf/ev-charging-and-pricing-what-are-consumers-willing-pay.

106 Bill LeBlanc, "EV Charging and Pricing: What Are Consumers Willing To Pay?"

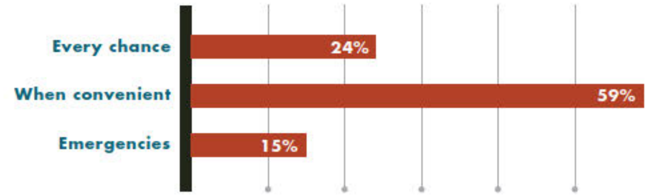
107 Bill LeBlanc, "EV Charging and Pricing: What Are Consumers Willing To Pay?"

108 Bill LeBlanc, "EV Charging and Pricing: What Are Consumers Willing To Pay?"

Fifty-seven percent of respondents are willing to pay a premium to use a DCFC.

Potential PEV owners, on the other hand, appear to be more price sensitive — their willingness to pay for public charging peaks at $1 per hour.

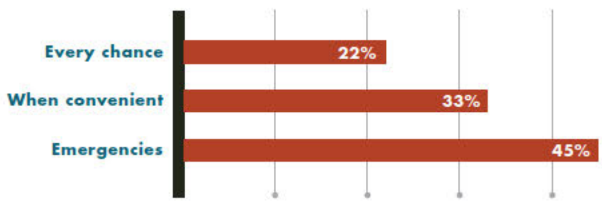
FIGURE 33: FREQUENCY OF USAGE WHEN RESPONDENTS ARE TOLD DCFC IS AVAILABLE AT A PREMIUM (2020)



Note: Data includes U.S. and Canada respondents who own or are considering owning a PEV.

Source: Bill LeBlanc, "EV Charging and Pricing: What Are Consumers Willing To Pay?"

FIGURE 34: FREQUENCY OF USAGE WHEN RESPONDENTS ARE TOLD DCFC IS AVAILABLE AT A PREMIUM AND ABOUT THE POSSIBILITY OF BATTERY DEGRADATION (2020)



Note: Data includes U.S. and Canada respondents who own or are considering owning a PEV.

Source: Bill LeBlanc, "EV Charging and Pricing: What Are Consumers Willing To Pay?"

When participants were asked how frequently they would use a DCFC if they had to pay a premium, 59% responded they would use it when convenient and 24% said they would plug in at every chance (Figure 33).[109] This response changed drastically when informed about the possibility of battery degradation with DCFC.[110] In that case, 45% said they would only use a DCFC in an emergency (up from 15%), and 33% said they would plug in when convenient (down from 59%) (Figure 34).[111]

109 Bill LeBlanc, "EV Charging and Pricing: What Are Consumers Willing To Pay?"

110 Idaho National Laboratory, *DC Fast Charge Effects on Battery Life and Performance Study – 50,000 Mile Update*, April 15, 2014, https://www.energy.gov/sites/prod/files/2015/01/f19/dcfc_study_fs_50k.pdf.

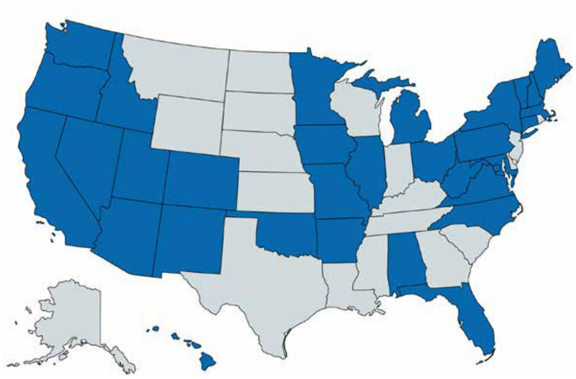
111 Bill LeBlanc, "EV Charging and Pricing: What Are Consumers Willing To Pay?"

EV CONSUMERS' PERCEPTION OF VARIOUS BILLING METHODS

In the 2013 PlugShare and PluginCars.com survey, the large majority of respondents (73%) preferred being charged by the energy used in recharging their vehicles as opposed to being charged by time spent recharging their vehicles.[112] The mindset of today's EV drivers is not very different from the findings of that survey — being charged by the energy drawn is very closely comparable to filling gas at a gas station in a conventional vehicle where the driver pays for the energy drawn and not by pumping time. Since that time, more than 30 states have allowed pricing per kWh instead of per minute. Both methods are now used, with Tesla declaring that charging per kWh to be most fair and simple. A shown by (Figure 35),[113] charging providers ChargePoint, EVgo, and Electrify America also offer this option.[114]

The University of Michigan Transport Research Institute conducted a study to assess respondents' preferred payment method, including current and prospective EV owners. The results showed that "pay-per-use" setup was marginally preferred over "automatic authorization," where pay-per-use involved providing an ID and billing information, such as a credit card, RFID card, or cash, and automatic authorization involved the vehicle identifying itself and the customer being charged on the payment method on file on their account (Figure 36).[115] Respondents marginally preferred a "pre-negotiated billing rate" as opposed to a "variable billing rate;" for a pre-negotiated billing rate, the driver would use pre-negotiated pricing

FIGURE 35: STATES PERMITTING KWH PRICING FOR EV CHARGING (2019-2020)



Source: ChargePoint, 25 States, DC, and Austin, Allow Third-Parties to Include per-kWh Fee in Pricing to Driver (aka, "Charge for Charging")*; Bengt Halvorson, "Electrify America Reboots Pricing, Bills EV Charging by the kWh Where It's Allowed"*

at any charging station, the vehicle would be identified by the EVSE, and the driver would be billed automatically to the payment method on file (Figure 37).[116]

Regarding cost and energy demand preference when using a public charger, 73% of respondents preferred "optimized charging" and 27% preferred "on-demand charging." Optimized charging in this context means charging would be optimized based on factors that affect cost, such as the vehicle's charging requirement and demand on the grid, with a definite pre-set end time. On-demand charging, on the other hand, means the vehicle is charged as quickly as needed without regards to reducing costs or electricity demand on the grid (Figure 38).[117]

112 Brad Berman, "Comprehensive Study of EV Drivers Reveals Plug-in Attitudes", plugincars.com, November 14, 2013, https://www.plugincars.com/comprehensive-study-ev-drivers-reveals-plug-attitudes-128883.html.

113 ChargePoint, *25 States, DC, and Austin, Allow Third-Parties to Include per-kWh Fee in Pricing to Driver (aka, "Charge for Charging")*, April 2019, https://assets.ctfassets.net/ucu418cgcnau/fYtvhoCe1g93DtTrZO5gS/83c2e4c2581a39d30ac293ce33472b42/2019_States_with_exemption_for_charging_April_2019.pdf; Bengt Halvorson, "Electrify America Reboots Pricing, Bills EV Charging by the kWh Where It's Allowed," *Green Car Reports*, September 16, 2020, https://www.greencarreports.com/news/1129626_electrify-america-reboots-pricing-bills-ev-charging-by-the-kwh-where-its-allowed.

114 Charles Benoit, "30 States Allow kWh Pricing, But Non-Tesla EV Drivers Mostly Miss Benefits," *Electrek*, August 12, 2019, https://electrek.co/2019/08/12/kwh-pricing-ev-drivers-miss-benefits/; "Supercharging," Support, Tesla, accessed October 18, 2020, https://www.tesla.com/support/supercharging.

115 Brandon Schoettle and Michael Sivak, *Consumer Preferences for the Charging of Plug-in Electric Vehicles* (Ann Arbor, MI: University of Michigan Sustainable Worldwide Transportation, November 2016), http://umich.edu/~umtriswt/PDF/SWT-2016-13.pdf.

116 Brandon Schoettle and Michael Sivak, *Consumer Preferences for the Charging of Plug-in Electric Vehicles*

117 Brandon Schoettle and Michael Sivak, *Consumer Preferences for the Charging of Plug-in Electric Vehicles*

FIGURE 36: PAYMENT AUTHORIZATION TYPE PREFERENCE WHEN CHARGING IN PUBLIC (2016)

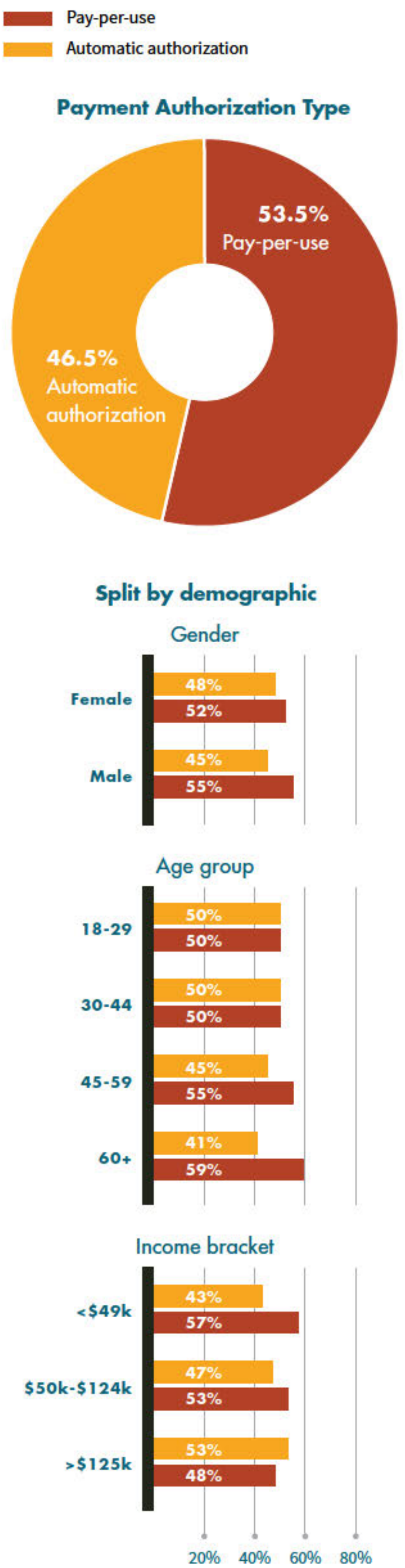


FIGURE 37: PRICING TYPE PREFERENCE WHEN CHARGING IN PUBLIC (2016)

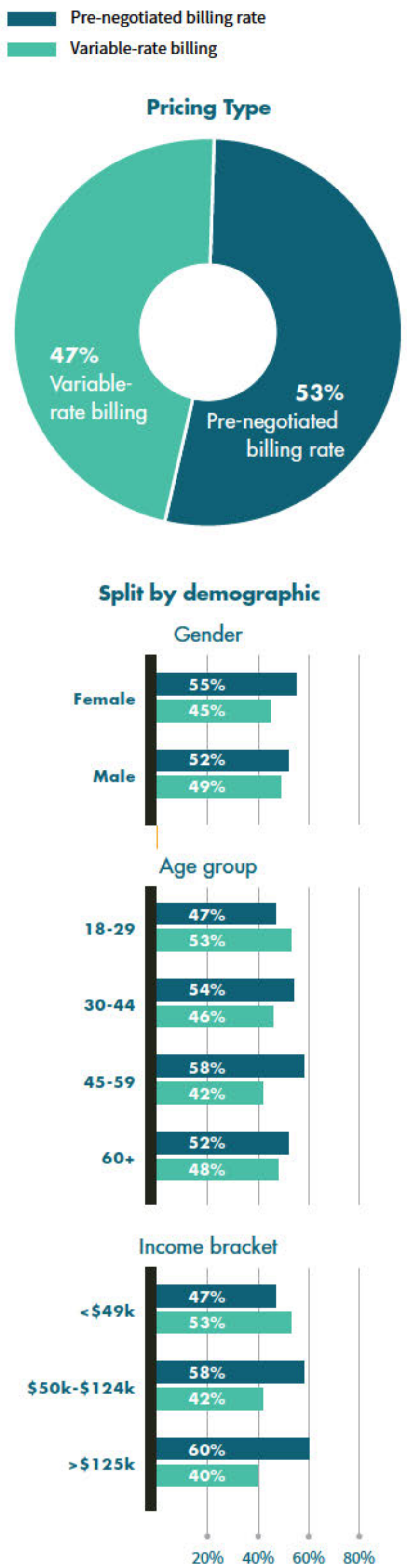
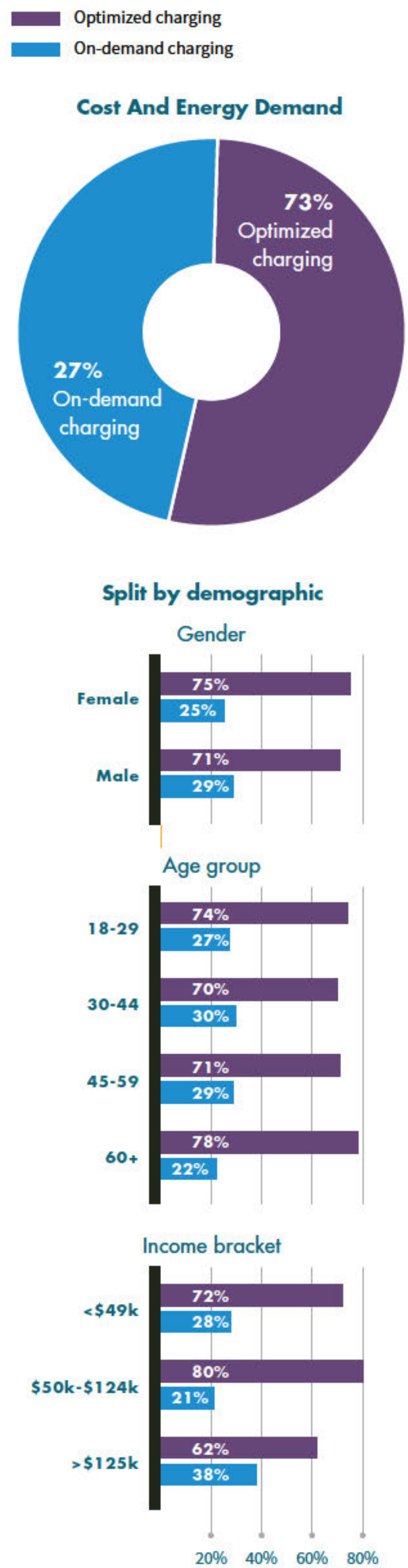


FIGURE 38: COST AND ENERGY DEMAND PREFERENCE WHEN CHARGING IN PUBLIC (2016)

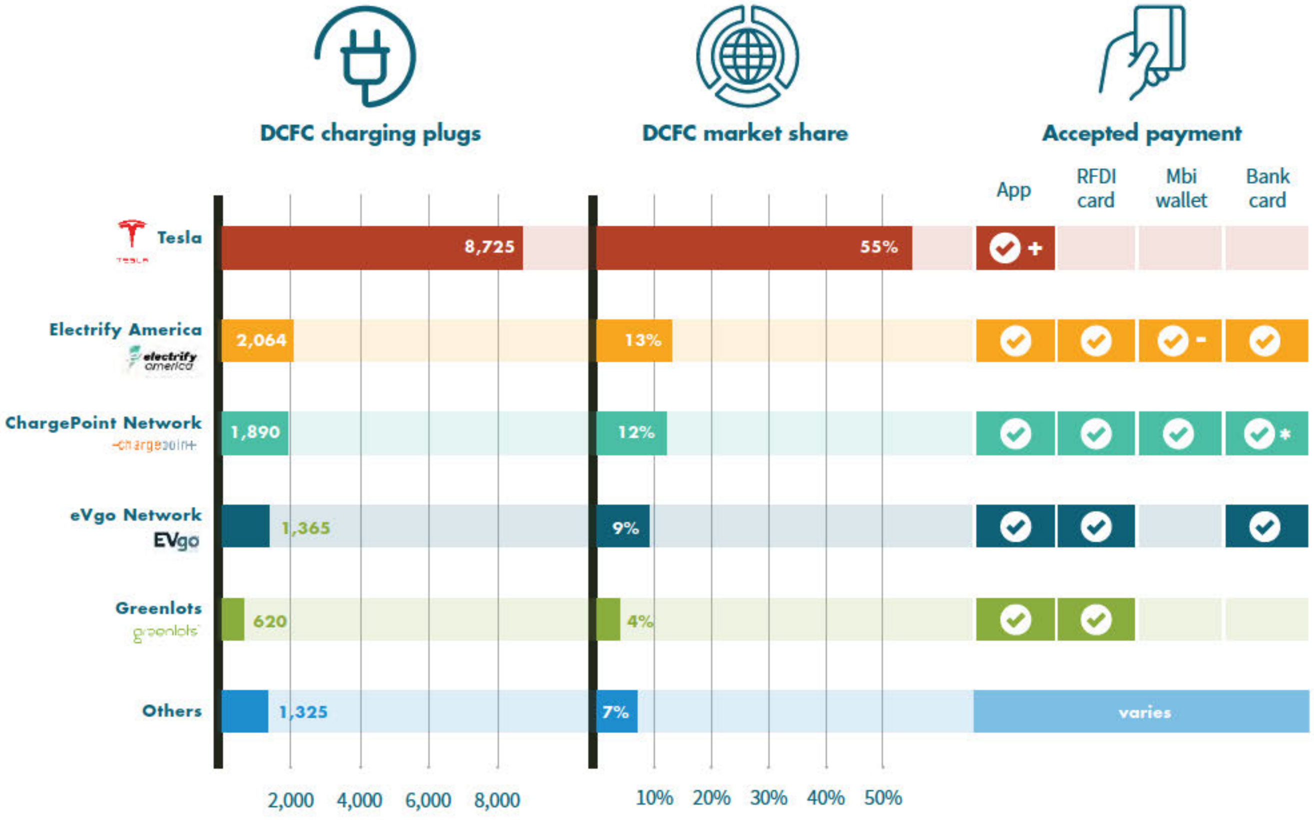


Source (Figures 36-38): Brandon Schoettle and Michael Sivak, Consumer Preferences for the Charging of Plug-in Electric Vehicles

EV CONSUMERS' COMFORT WITH THE VARIOUS PAYMENT OPTIONS

The top five networks make up approximately 93% of all DCFC chargers in the U.S. The payment methods offered by these networks, when analyzed, appear to all support in-app payments, excluding Tesla's Supercharger network (Figure 39).[118] Tesla Superchargers identify the vehicle and charge the account on file when a charging occasion is initiated. Tesla's Supercharger network forms 55% of the DCFC network in the U.S. but is not accessible to drivers of other vehicles.[119] Excluding the Tesla network, the other major providers also accept RFID authentication via their membership card according to their respective websites. Electrify America, ChargePoint, and EVgo also accept payments directly from a credit card at the charger, and the former two also support mobile payment like Apple Pay and Samsung Pay.[120]

FIGURE 39: INFOGRAPHIC OF TOP DCFC NETWORKS, NUMBER OF PLUGS, U.S. DCFC MARKET SHARE, AND ACCEPTED PAYMENT TYPES (2020)



+ *Integrated into the interface, and funds are withdrawn automatically from linked source*
- *Since tap credit cards are accepted, mobile wallets like Apple Pay and Google Pay would work as well*
* *Only RFID tap-enabled credit cards are accepted at the station*

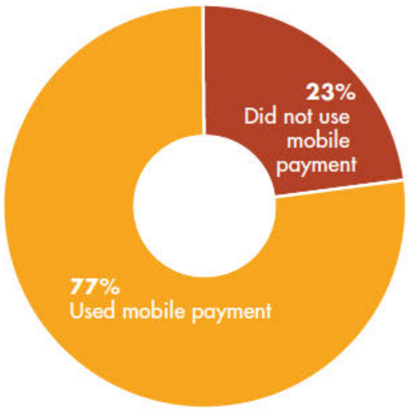
Source: "Alternative Fueling Station Locator," Alternate Fuels Data Center

118 "Alternative Fueling Station Locator," Alternate Fuels Data Center; "Supercharging," Support, Tesla, accessed October 18, 2020, https://www.tesla.com/support/supercharging; "Pricing and Plans for EV Charging," Electrify America, accessed October 18, 2020, https://www.electrifyamerica.com/pricing/; "EV Driver Support," ChargePoint, accessed October 18, 2020, https://www.chargepoint.com/en-ca/support/driver-faq/; "EVgo Charging 101," EVgo, accessed October 18, 2020, https://www.evgo.com/pricing/; "What You Can Do With Our Mobile App," EV Drivers, Greenlots, accessed October 18, 2020, https://greenlots.com/ev-drivers/.

119 "Alternative Fueling Station Locator," Alternate Fuels Data Center

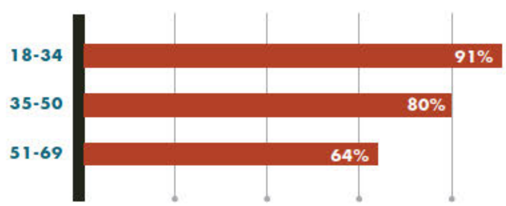
120 "Pricing and Plans for EV Charging," Electrify America; "EV Driver Support," ChargePoint; "EVgo Charging 101," EVgo

FIGURE 40: PERCENTAGE OF RESPONDENTS WHO HAVE USED MOBILE PAYMENT (AUGUST 2018 TO AUGUST 2019)



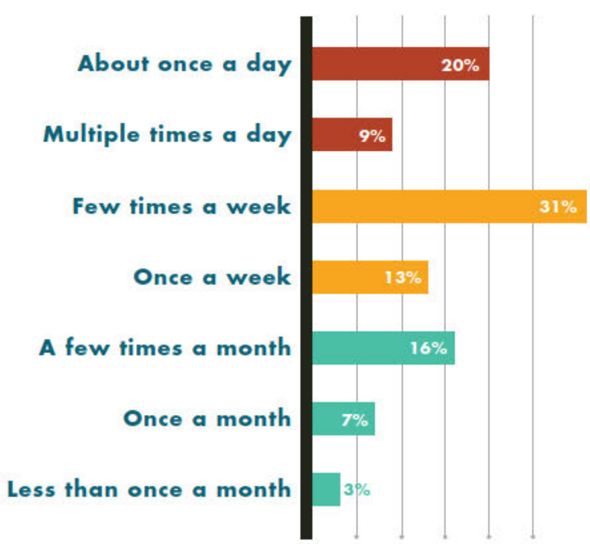
Source: Lindsay Anan et al., Are Convenience and Rewards Leading to a Digital Flashpoint?

FIGURE 41: PERCENTAGE BY AGE GROUP OF RESPONDENTS WHO HAVE USED MOBILE PAYMENT (AUGUST 2018 TO AUGUST 2019)



Source: Lindsay Anan et al., Are Convenience and Rewards Leading to a Digital Flashpoint?

FIGURE 42: PERCENTAGE OF U.S. CUSTOMERS WHO MAKE MOBILE PAYMENTS (2019)



Source: Jamie Gonzalez-Garcia and Kelly Dilworth, "Online and Mobile Payment Statistics"

In a survey conducted by McKinsey in the U.S. between August 2018 and August 2019, 77% of all respondents used mobile payment (Figure 40)[121] with 80% mobile payment users within the ages of 35 and 50 (Figure 41).[122] The top EV demographic of between the ages of 40 and 55 overlaps with this user base. A separate 2019 survey by Pymnts found that 73% of respondents made mobile payments at least once a week (Figure 42).[123] It may be safe to assume that EV users are currently comfortable with the available payment method choices.[124]

121 Lindsay Anan, Deepa Mahajan, and Marie-Claude Nadeau, *Are Convenience and Rewards Leading to a Digital Flashpoint? Insights from McKinsey's 2019 Digital Payments Survey* (San Francisco, CA: McKinsey and Company, October 2019), https://www.mckinsey.com/~/media/mckinsey/industries/financial%20services/banking%20blog/are%20convenience%20and%20rewards%20leading%20to%20a%20digital%20flashpoint/mckinsey-2019-digital-payments-survey.ashx.

122 Lindsay Anan et al., *Are Convenience and Rewards Leading to a Digital Flashpoint?*

123 Jamie Gonzalez-Garcia and Kelly Dilworth, "Online and Mobile Payment Statistics," CreditCards.com, April 20, 2020, https://www.creditcards.com/credit-card-news/online-payment-statistics-1276/.

124 Jamie Gonzalez-Garcia and Kelly Dilworth, "Online and Mobile Payment Statistics"

WHAT DO CUSTOMERS DO AT FACILITIES WHILE CHARGING?

DWELL TIME AT PUBLIC CHARGERS AND THE FEATURES THAT COULD INFLUENCE THAT DWELL TIME

Potential EV consumers expect to spend between 30 minutes and 1 hour at a charging station.[125] The average fleet customer wants to spend 36 minutes on average.[126] This is on par with the global average of 31 and 36 minutes respectively (Figure 43).[127]

A few trends emerge when analyzing the prevalent factors that influence the dwell time at a public charger:

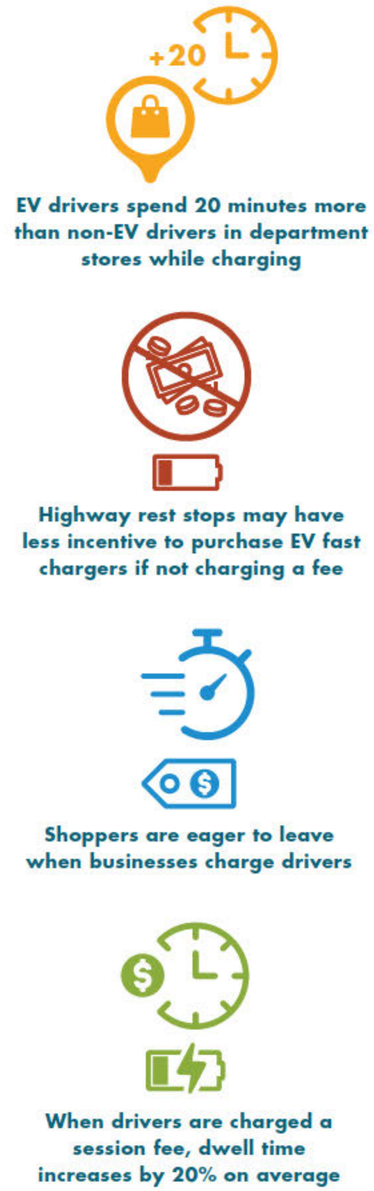
1) **EV drivers dwell 20 minutes longer than non-EV drivers:** Kohls found that EV drivers, when provided on-premise car charging facility, spend 20 minutes more in the store than non-EV drivers; Target found EV drivers spend more than three times longer in the store.[128]

2) **Highway rest stops may have less incentive to purchase EV fast chargers if not charging a fee:** Business owners pay demand-based electricity rates. Having a free on-premise DC charger and the corresponding quick charge time translated to lesser dwell time and thus lesser revenue but a high electricity bill for the business (see following discussion on cost of installation for the business).[129]

3) **Shoppers are eager to leave when businesses charge drivers:** When charging is outsourced to third-party operators, charging becomes five times the cost and thus shoppers become clock watchers and are eager to leave as soon as they have enough power to do so.[130]

4) **When drivers are charged a session fee, the dwell time increases by 20% on average:** For Blink chargers, prior to the onset of charges, an average session lasted 19.5 minutes. When a session fee was levied, users tended to stay 20% longer, presumably to get more value.[131] This billing structure is outdated, and customers are now billed by the energy used.

FIGURE 43: FACTORS AND FEATURES THAT INFLUENCE OVERALL EXPECTED DWELL TIME AT PUBLIC CHARGERS



Source: Jim Burness, "Don't Let Someone Else's Profit Center Ruin Your Amenity"

125 Deloitte, *2020 Global Automotive Consumer Study: Tracking Key Changes in the Automotive Industry*, 2019, available at https://www2.deloitte.com/us/en/pages/manufacturing/articles/automotive-trends-millennials-consumer-study.html; Castrol, *Accelerating the EVolution*

126 Castrol, *Accelerating the EVolution*

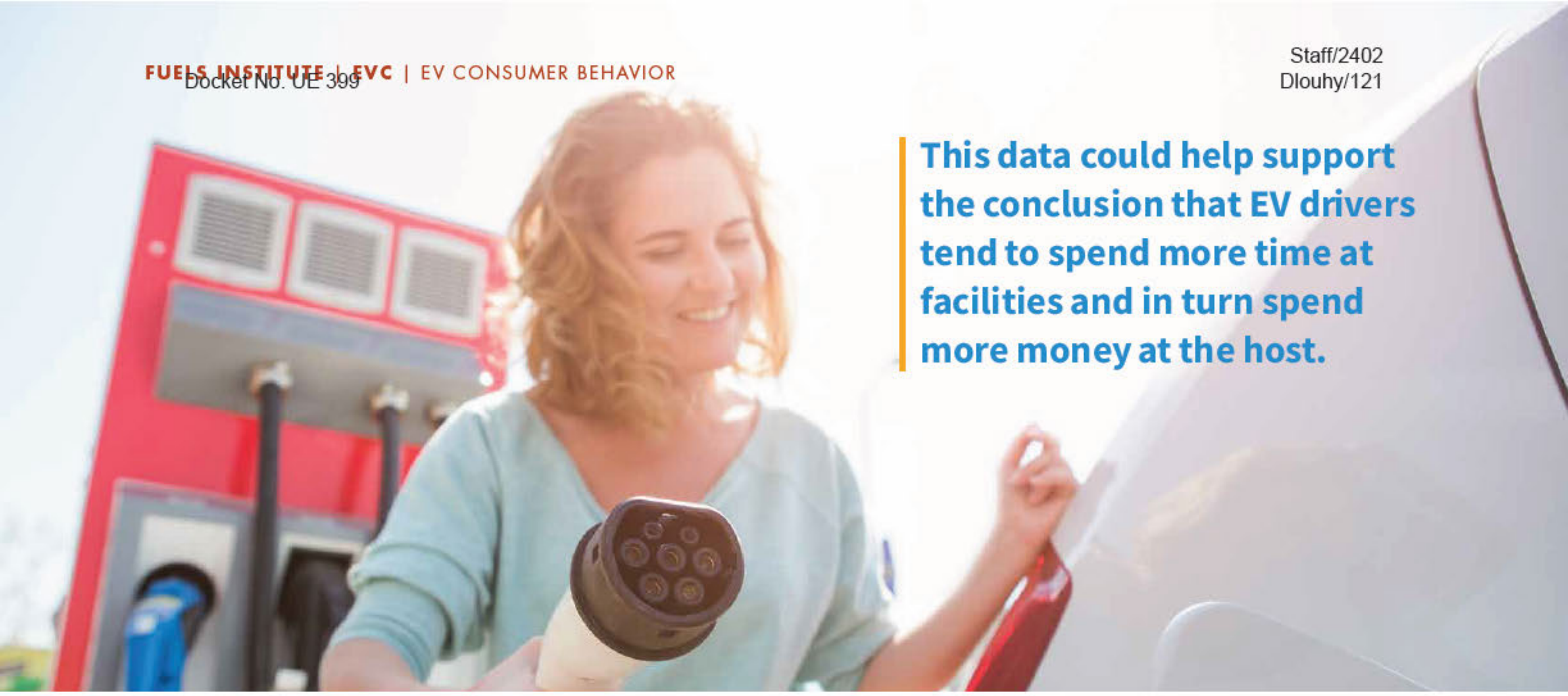
127 Jim Burness, "Don't Let Someone Else's Profit Center Ruin Your Amenity," *National Car Charging*, July 12, 2015, https://www.nationalcarcharging.com/blogs/news/48795587-dont-let-someone-elses-profit-center-ruin-your-amenity; David Thill, "The Need For Charging Stations Is Clear, But Who Should Own Them Is Not," Energy News Network, February 15, 2019, https://energynews.us/2019/02/15/midwest/the-need-for-charging-stations-is-clear-but-who-should-own-them-is-not/; John Galloway Smart and Shawn Douglas Salisbury, *Plugged In: How Americans Charge Their Electric Vehicles*

128 Jim Burness, "Don't Let Someone Else's Profit Center Ruin Your Amenity"; ChargePoint, "Leading Retailer Partners with ChargePoint to Attract and Retain Loyal Customers," news release, 2015, https://www.chargepoint.com/files/casestudies/cs-retail.pdf.

129 David Thill, "The Need for Charging Stations Is Clear, But Who Should Own Them Is Not"

130 Jim Burness, "Don't Let Someone Else's Profit Center Ruin Your Amenity"

131 John Galloway Smart and Shawn Douglas Salisbury, *Plugged In: How Americans Charge Their Electric Vehicles*



This data could help support the conclusion that EV drivers tend to spend more time at facilities and in turn spend more money at the host.

Target, in its pilot program in collaboration with ChargePoint, noted that with the introduction of EV charging stations on-site, the average dwell time was 72 minutes per session, which was 50 minutes greater than the average dwell time of 22 minutes without EV charging stations. Drivers also spent approximately $1 per minute more on average at the store, and the gross additional revenue was estimated to be around $56,000 while the cost of electricity for the charger was estimated to be $430 during the test period.[132]

According to the Bureau of Labor Statistics, on average, the time spent by customers making consumer goods purchases was approximately 52 minutes (including transit time),[133] and Atlas Public Policy's study for the New York State Energy Research and Development Authority found that the average charging duration per session, at retail locations in New York City, recorded an average of 2 hours and 36 minutes of dwell time despite an average charging duration lasting only two hours during the session.[134] Similarly, Origins, a cosmetics retailer, while using a new business model that included methods to increase customer dwell time, found a 20%-40% boost in their revenue from increased customer dwell time.[135] This data could help support the conclusion that EV drivers tend to spend more time at facilities and in turn spend more money at the host.

In National Car Charging's 2019 survey of PEV drivers, 81% of respondents said that availability of a charging station at businesses makes them more loyal to the business.[136] EV charging stations can boost business by building the retailer's "green" image and in turn attracting new customers while building customer loyalty.[137]

132 ChargePoint, "Leading Retailer Partners with ChargePoint to Attract and Retain Loyal Customers"

133 Bureau of Labor and Statistics, U.S. Department of Labor, "American Time Use Survey — 2019 Results," news release, June 25, 2020, https://www.bls.gov/news.release/pdf/atus.pdf.

134 New York State Energy Research and Development Authority, *Assessing the Business Case for Hosting Electric Vehicle Charging Stations in New York State*, June 2019, https://atlaspolicy.com/wp-content/uploads/2019/09/19-31-Business-Case-for-Hosting-Charging-Stations.pdf.

135 Melissa Fulenwider, "The Rising Influence of the 'Slow Shopping Theory,'" *Business Today Online Journal*, February 14, 2016, https://journal.businesstoday.org/bt-online/2017/the-rising-influence-of-the-slow-shopping-theory.

136 Margaret-Ann Leavitt, "Do EV Charging Stations Make for More Loyal Customers? Survey Says: They Certainly Do.," National Car Charging (article published on LinkedIn), June 17, 2019, https://www.linkedin.com/pulse/do-ev-charging-stations-make-more-loyal-customers-survey-leavitt/.

137 Brian W. Blaesser and Sorrell E. Negro, "Electric Vehicle Charging Stations — Retail Primer Update," International Council of Shopping Centers, accessed October 23, 2020, available at https://www.icsc.com/newsletters/article/electric-vehicle-charging-stationsretail-primer-update.

TABLE 1: COST OF OPERATION PER HOUR AT VARIOUS CHARGING LEVELS (DIRECTIONAL ESTIMATES)

CHARGER TYPE AND ENERGY	CAPITAL COST	CAPITAL COST				
					COST INCURRED BY HOST	
		Electricity cost [A]	Amortization of capital [B]	Depreciation [C]	First 5 years [A]+[B]+[C]	Next 5 years [A]+[C]
Level 2 (7.7 kW)	$2,500	$0.82	$0.17	$0.07	$1.06	$0.89
Level 2 (12.25 kW)	$3,700	$1.31	$0.25	$0.10	$1.66	$1.41
Level 2 (16.8 kW)	$4,900	$1.79	$0.34	$0.13	$2.27	$1.93
Level 3 (50 kW)	$27,900	$5.34	$1.92	$0.77	$8.02	$6.11
Level 3 (150 kW)	$87,800	$16.02	$6.03	$2.41	$24.46	$18.43
Level 3 (350 kW)	$139,000	$37.38	$9.55	$3.82	$50.75	$41.20

Note: Assumption of charging use for amortization and depreciation is eight hours per day every day through the year. Higher and lower costs are assigned to higher and lower powered chargers and the mid-value is the average of the two in terms of power and cost. Costs and prices are directional estimates. Cost of charger does notinclude "make-ready costs" (e.g., transformers) and service/maintenance costs. Costs assumed are average cost. Level 2 12.25 kWh charger cost is estimated as average cost of Level 2 charger based on upper and lower limits.

However, for the business, the cost of installing a public Level 2 charging station could be between $2,500 and $4,900, depending on the location of installation, and a DCFC can cost between $20,000 and $150,000 per station.[138] The average cost of commercial electricity in 2019 was 10.68¢ per kWh.[139] Power draw on a Level 2 charger can range from 7.7 to 16.8 kW,[140] and DCFC can range between 50 kW to 350 kW. Table 1 summarizes the expense per hour to host at various charging levels. Amortization and depreciation are calculated with an assumption of eight hours use every day of the year. Salvage value is calculated at 20% of overall cost.

Given the charge time to get an EV to 80% at a fast charger is around 20 to 30 minutes, the cost of operation of a 150-kWh charger is approximately $7-$12 (Table 1). Highway rest stop businesses are typically convenience stores. The average pre-tax profit margin of a convenience store is 3.2%,[141] which means that the driver should spend at least $312 (assuming $10 operation cost) for the convenience store to break even and far more for it make a profit. To put this in perspective, the average driver spends between $8 and $11 per visit.[142]

138 Chris Nelder and Emily Rogers, "Reducing EV Charging Infrastructure Costs," Rocky Mountain Institute, 2019, https://rmi.org/ev-charging-costs.

139 "Average Retail Price of Electricity, United States, Annual," Electricity Data Browser

140 "Guide on Charging Your Electric Vehicle at Home," ChargeHub, accessed October 23, 2020, https://chargehub.com/en/home-charging-guide-electric-vehicles.html.

141 "Convenience Stores," "Food and Beverage Stores," "Benchmarks," The Retail Owners Institute, accessed October 27, 2020, https://retailowner.com/Benchmarks/Food-and-Beverage-Stores/Convenience-Stores.

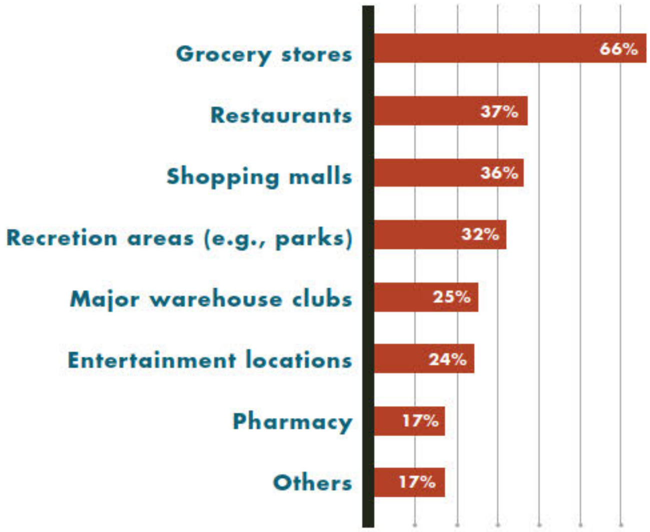
142 Brandon Logsdon, "A 2020 Outlook on Convenience Store Retail Trends," *Convenience Store News*, January 29, 2020, https://csnews.com/2020-outlook-convenience-store-retail-trends.

FEATURES AND AMENITIES THAT ARE MOST DESIRED BY EV DRIVERS, USED DURING A CHARGING SESSION, AND COULD INFLUENCE DRIVERS TO USE CHARGING STATIONS FREQUENTLY

Consumer Reports and UCS found that 66% of the participants in their 2019 survey viewed grocery stores to be most convenient to have a charging station.[143] The broad majority seemed to support having a charging station where they would spend longer periods of time anyway. This was also the finding in the study conducted by INL and the DOE in which shopping malls, airports, commuter lots, and downtown parking lots with easy access to a variety of venues were amongst the most used public charger locations. As shown in (Figure 44),[144] INL and the DOE further found that Level 2 charging sites at retail stores, shopping malls, parking lots, and garages demonstrated the potential to support seven to 11 charges a day.[145]

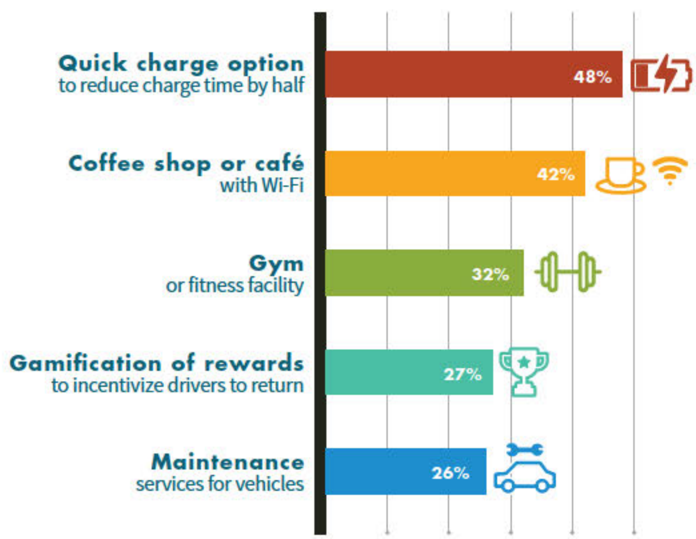
Volvo, in their 2018 study, found that among the most desired charging station features, the option to quickly charge a vehicle in half the time topped the list. Having a coffee shop with Wi-Fi to increase productivity during the downtime was the second preferred option, and having a gym to work out was number three on the list. An interesting observation was that 27% of the respondents felt that "gamification of rewards" would encourage them to use the chargers more often. A quarter of the participants also felt the need for maintenance services to be provided on-site (Figure 45).[146]

FIGURE 44: EV CHARGING LOCATIONS PERCEIVED TO BE MOST CONVENIENT BY POTENTIAL EV CUSTOMERS (2019)



Source: Union of Concerned Scientists and Consumer Reports, Electric Vehicle Survey Findings and Methodology

FIGURE 45: FEATURES MOST DESIRED AT EXISTING EV CHARGING LOCATIONS (2019)



Note: Participants chose more than one option

Source: Volvo Car USA, The State of Electric Vehicles in America

143 Union of Concerned Scientists and Consumer Reports, *Electric Vehicle Survey Findings and Methodology*

144 Union of Concerned Scientists and Consumer Reports, *Electric Vehicle Survey Findings and Methodology*

145 John Galloway Smart and Shawn Douglas Salisbury, *Plugged In: How Americans Charge Their Electric Vehicles*

146 Volvo Car USA, *The State of Electric Vehicles in America*

FEATURES AND AMENITIES THAT YIELD THE GREATEST INFLUENCE OVER AN EV DRIVER'S DECISION REGARDING WHERE TO CHARGE

A few key factors that influence a driver's decision in choosing where to charge are (Figure 46):

1) **Dependability:** Some networks appear to be more dependable than others. Chargers at newer stations have been found to be out of service.[147]

2) **Convenience:** Drivers are less likely to plug in at work if they have to pay to charge or if they have to move the vehicle after charging (and the rule was enforced).[148]

3) **Cost of use:** Most Blink public units started charging a fee after September 2012 while ChargePoint units were free through the end of the DOE's EV Project. Usage of ChargePoint units had been increasing at a faster rate than Blink.[149]

4) **Need for travel:** Drivers who plugged in away from home generally traveled more, logging 72% more daily miles on electricity compared to drivers who didn't charge at home. Most used chargers that tended to be closer to highway exits.[150]

FIGURE 46: KEY FEATURES AND AMENITIES THAT INFLUENCE EV DRIVERS' CHOICE OF CHARGER

147 Jeff Plungis, "How the Electric Car Charging Network Is Expanding"

148 Eric Schmidt, "The Key to Increasing EV Adoption Is Hidden in EV Driving and Charging Data"

149 Eric Schmidt, "The Key to Increasing EV Adoption Is Hidden in EV Driving and Charging Data"

150 Eric Schmidt, "The Key to Increasing EV Adoption Is Hidden in EV Driving and Charging Data"

Consumer Reports and UCS found that 66% of the participants in their 2019 survey viewed grocery stores to be most convenient to have a charging station.

PERSONA FINDINGS

These five personas exemplify predicted individual preferences. They were chosen to represent various demographics, their use cases, and perceptions of EV ownership and charging. More details, including their daily habits, are outlined in the following pages.

PERSONA FINDINGS

Michael

Affluent Middle-Aged White Male With BEV As Secondary Vehicle Living in the California Bay Area With Access to At-Home Charging

OVERVIEW

Michael is an affluent middle-aged white man who owns more than one vehicle. He fits the most common EV owner demographic and exemplifies their typical EV-related behavior. He lives in the ZEV-populous Bay Area region of California, considers driving a Tesla to be a status symbol, and likes being associated with cutting-edge technology.

Michael generally charges at home and uses free charging at his workplace parking lot. He uses public chargers when they are free and when the charge time fits his schedule. Michael only recharges with a DCFC when unavoidable and prefers the Tesla network since the ecosystem is integrated within the vehicle and the smartphone app. He also limits himself to using Level 2 chargers because of the potential battery degradation from frequently using a DCFC. This could be another aspect to consider when designing EV charging infrastructure — this is in line with the current projection of 96% of public chargers being Level 2 (Figure 25). Michael does not choose a particular gym based on the availability of charger, exemplifying that people may not switch loyalty to a business solely based on the availability of a public charger.

For long trips, Michael chooses to fly as opposed to road-trip, or he and his family use the gasoline-powered SUV. Michael might consider an electric SUV if the DCFC network along highways was denser and the charging time was much lower.

PERSONA DESCRIPTION

- 37-year-old male
- Owns Tesla Model 3, second car ($60,000); first car is a premium SUV
- Lives in the Bay Area, California
- Married, two kids (below age 6)
- Director at a technology company
- $400,000 household income
- Owns a house with garage and usually charges at home at night
- One-and-a-half hour commute to and from work everyday
- Occasional road travel out of the city
- Workplace has free charging
- Nanny comes in on the weekend for four hours once a month so that Michael and his wife can step out for dinner and shopping using the Tesla

PERSONA FINDINGS: MICHAEL

TRAITS

TYPE OF CUSTOMER

- Considers driving a Tesla to be a status symbol
- Is undergoing a mid-life crisis and taking time for self-care and family care
- Values the green credential that comes with owning an EV
- Likes being on the cutting-edge of technology
- Identifies as an early tech adopter
- Likes “cool” things
- Identifies as a beta tester of new tech
- Prefers flying to road travel for long trips

RECHARGE HABITS

- Recharges at home every or every other night
- Recharges at public parking that provides free parking and free electricity
- Plugs in when parking is closer to the building
- Recharges primarily at home and work (free charging) and at hotels when on trips
- Does not wait until the battery is nearly empty and always keeps it topped up
- Would use a public charger if there happens to be a saturation in the residential energy market or if urban housing has the facility to plug in

CHOOSING A PARTICULAR CHARGING FACILITY

- Only recharges using a Level 2 DCFC when almost empty and unavoidable
- Would prefer to charge within the Tesla network that is integrated in the vehicle’s interface
- Charges for free at the high-end shopping mall or an upscale restaurant when he goes out with his wife on a weekend (monthly)

INTERACTION WITH A PUBLIC CHARGING STATION

- Primarily recharges at home or work and has limited opportunity to use public chargers
- Would plug in if free of charge and if he plans to spend some time at that location
- Prefers using the Tesla Supercharger network if necessary but limits himself to Level 2

TIME SPENT AT A PUBLIC CHARGING STATION

- Would prefer to have a charging station at a gym or somewhere he is likely to spend time
- Would not choose a gym because of the availability of a charger, but having one would be good
- Would pay to charge at a public charger if it means he can park closer in a crowded lot
- Would use a public charger if there aren’t other parking lots nearby
- Uses the gasoline SUV for road trips with family

PERSONA FINDINGS

Shou

Affluent, Middle-Aged Asian American Male With BEV As Secondary Vehicle Living With At-Home Charger Who Frequents a Metropolitan City

OVERVIEW

Shou represents a slightly different demographic where the vehicle is often driven locally and occasionally to a metropolitan city. Shou, like Michael, primarily charges his car at home, but since he runs a business from home, his travel needs are lighter than Michael's.

Shou enjoys having an environmentally conscious image and appreciates the hassle-free ownership experience involved in driving an EV. Switching to an EV has not greatly impacted his travel habits because most of his trips are running errands around town. He prefers to take the bus or train instead of driving whenever convenient. When he does travel longer distances, he plans his trips around chargers and chooses to stay at hotels with a Level 2 charger to charge overnight. Shou's example of charging at the hotel where he stays overnight is in line with the observations that 1) the most used chargers are those at locations where people tend to park for long periods of time and 2) customers are attracted to businesses that provide an on-premise charger (see "Dwell Time at Public Chargers and the Features That Could Influence That Dwell Time" for an analysis of the profitability of this use case).

Shou's charging behavior is influenced by factors discussed in "EV Drivers' Preferred Recharge Location" although the majority of his charging is done at home, he tends to plug in when a charger is available, free, and convenient and if it helps secure a good parking spot. Shou's EV purchase included a ChargePoint card and he has received good customer service from the charge company, so he is loyal to that particular charger brand. Shou is also loyal to ChargePoint because he doesn't want to sign up for several charging apps. However, he uses the PlugShare app to scout for free chargers. He would prefer to be in a coffee shop with free Wi-Fi to increase his productivity during the downtime while charging, but during the current pandemic, he sits in the car.

PERSONA FINDINGS: SHOU

PERSONA DESCRIPTION

- 49-year-old male
- Owns Chevy Bolt as a second car; the first car is a minivan (primarily driven by his wife)
- Lives in New Jersey within the New York City metro area
- Married, two kids (in college)
- Owns a home-based financial firm
- $200,000 household income
- Owns a house with garage and usually charges at home
- Drives the Bolt in the evenings and over the weekend
- Frequently travels to Manhattan
- Prefers public transport when convenient

TRAITS

TYPE OF CUSTOMER

- Grown children no longer live at home, so he downsized the second car
- Environment-conscious image
- Appreciates the lower fuel cost with an EV
- Enjoys hassle-free ownership and prefers a low-maintenance vehicle
- Does not drive enough to justify having two cars and is considering selling the minivan
- Travel has not changed since switching to an EV — primarily uses it to travel around town and to the train station

RECHARGE HABITS

- Mostly recharges at home unless traveling
- Plans trips around chargers, and for work-related road trips, prefers to stay overnight in hotels offering Level 2 charging
- Would make long trips if the one-way distance is well within the car's range
- Prefers to use public chargers if charging is free and he has the time; otherwise he will only use a public charger if the car is running out of range
- Will charge while grocery shopping if it's free and he can get a good parking spot
- Very low tolerance to wait for a public charger because he can charge at home

CHOOSING A PARTICULAR CHARGING FACILITY

- Only recharges at Level 2 charger because DCFC on the Bolt is an optional extra ($700-$1,000)
- Prefers ChargePoint since the vehicle came with their charge card and they have good customer service
- Finds it a hassle to sign up for multiple apps
- Checks for free chargers on PlugShare

INTERACTION WITH A PUBLIC CHARGING STATION

- Prefers free charging unless out of range
- Finds signing up for new apps annoying
- Would prefer to pay through the app

TIME SPENT AT A PUBLIC CHARGING STATION

- Tries to get work done when waiting — prefers a café with Wi-Fi and outlets to plug in
- Needs a place to sit down and eat, a clean bathroom, and a convenience store
- Chooses to stay in the car while charging during the pandemic
- Would shop at a grocery store or a gas station's convenience store if there were available chargers

PERSONA FINDINGS

Raj

Middle-Class Young Male of Indian Heritage With BEV As Primary Vehicle for a 20-Mile Commute Who Lives in an Apartment Building with Shared Chargers

OVERVIEW

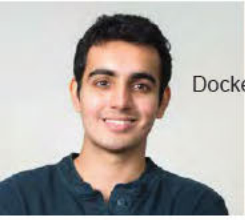
Raj is a little shy of the $100,000 annual household income bracket that makes up the dominant demographic. Being younger than the average age group of today's EV drivers and living in an apartment without access to a private charger makes Raj stand out among EV buyers. However, living in a major city with a 20-mile commute in stop-and-go traffic makes him an ideal candidate to own an EV.

Raj typically charges at his workplace every day because a charger isn't always available at home. He plans his trips around chargers when traveling between cities. Raj, like Michael and Shou, enjoys the green image that comes with driving an EV. Although Raj would switch grocery stores for free charging, he would not consider switching his tennis club for another one with a free charger.

This accentuates the possibility that while a free charger can promote business at some places, at others it would only remain a nicety. This could, however, become a necessity as the EV adoption rate increases in the future. Raj is well educated and mindful of the fact that frequent use of DCFC could accelerate battery wear. He ensures his recharging habits maintain the battery's optimum charge level to extend battery life. This behavior could become commonplace amongst the more enthusiastic owners and eventually could pressure the infrastructure market to address this requirement by incorporating a means to monitor and control charging level and speed. Raj is, in general, unwilling to pay for charging. When unavoidable, he expects payments to be seamless.

PERSONA DESCRIPTION

- 28-year-old male
- Owns Tesla Model 3
- Lives in Chicago, Illinois
- Single
- Electrical/electronics engineer
- $90,000 household income
- Lives in a rental apartment complex with two charging plugs
- Commutes 20 miles daily
- Occasionally road-trips with friends
- Relatives live in Ann Arbor, Michigan, and he visits once every three months; there is no charger at his destination
- Plays tennis three times a week



PERSONA FINDINGS: RAJ

TRAITS

TYPE OF CUSTOMER

- Charges at work every day
- Plans road trips based on Superchargers
- On trips to Ann Arbor, charges for 20 to 30 minutes in both directions
- Supports the "green" theme
- Appreciates getting "fuel" for free
- Enjoys status symbol of driving a Tesla

RECHARGE HABITS

- Mostly charges at work because the charger at home is not always available
- Would plug in whenever possible but is mindful to not charge above the "safe" range of the battery
- A battery level of less than 35% is his trigger point to plug in, and he calculates the way back to his regular locations or plugs in as soon as he can
- Plugs in even at a Level 1 charger for free "fuel"
- Would switch grocery stores for a priority spot and free charging
- Would not switch tennis clubs for a free charger
- Plugs in when there is an EV-only parking structure that's closer to where he wants to be

CHOOSING A PARTICULAR CHARGING FACILITY

- On the highway, would prefer a DCFC but wouldn't complain about having a Level 2 elsewhere
- Around town, does not plug in to a DCFC unless he must because of battery degradation
- Safety of the vehicle is more important than the identity of the charger or the host
- Prefers to use the car's interface, but uses EVgo and ChargePoint when not using Tesla EVSE

INTERACTION WITH A PUBLIC CHARGING STATION

- Reluctant to pay for charging, which should be as seamless as possible if he must pay
- Would pay a premium to use renewable energy

TIME SPENT AT A PUBLIC CHARGING STATION

- Aims to spend 20 to 30 minutes at a charger and call friends and family when charging
- Needs facilities similar to those at a conventional gas station — bathroom, coffee, and snacks
- Would like nearby services such as free Wi-Fi (streaming level), charging ports, gym, and games (similar to Dave and Busters)
- Would extend his stay at a public charger if there were a treadmill, shower, and food

PERSONA FINDINGS

Millicent

Retired Environmentally Conscious African American Female on a Fixed Income With a BEV As a Primary Vehicle With an At-Home Charger

OVERVIEW

Millicent, who is on a fixed income and has predictable traveling patterns, prefers to take the train when going downtown but travels in her EV to promote environmentally conscious behavior among her circle of influence. She considers her EV to be more of a political statement than a transportation choice.

Millicent has limited daily traveling needs and charges mostly at home on a Level 1 charger. She uses public chargers to promote awareness of EVs. She enjoys conversations with like-minded people whom she often meets at these public chargers. Although she does not need to use a public charger very often, she expects to see a lot more chargers in her community for the people who would need to use them. She is not very tech-savvy and does not use apps to find chargers. She only uses chargers that she's seen or are at places that she frequently visits. She treats her car like a gasoline-engine powered car, which reflects the anticipation that as EV adoption becomes more widespread, EVs will be treated like today's conventional vehicles. Facilities and amenities offered at public chargers do not affect Millicent's frequency or duration of usage of those public chargers.

PERSONA DESCRIPTION

- 68-year-old female
- Drives used Chevy Bolt
- Lives in Orlando, Florida
- Living alone; her adult children live in the Chicago metro area
- Retired elementary school teacher
- $60,000 fixed pension
- Owns a house with garage
- Leaves house only a few times a week
- Takes the train when traveling downtown
- Involved in both the civil rights and environmental justice movements in her youth and wants to make purchasing choices that are aligned with her values

PERSONA FINDINGS: MILLICENT

TRAITS

TYPE OF CUSTOMER

- Involved with community and church and volunteers at the local library
- Environmentally conscious
- Owning an EV is more of a political than a transportation choice; she cares about how air pollution is disproportionally affecting her community and feels that she is making a difference through her choice of transportation
- Only person in her social circle to own an EV
- Travel has not changed since switching to an EV and remains minimal

RECHARGE HABITS

- Mostly charges at home (Level 1 charger)
- Uses free public chargers at the library and around town to bring awareness to onlookers; identifies as an advocate for EVs
- Plugs in at readily available chargers for conversations with like-minded people
- Is proud of not using a gas station in years
- Would like to see more chargers in the community so that they are accessible to people who drive more than she does

CHOOSING A PARTICULAR CHARGING FACILITY

- Does not know the difference between Level 1, Level 2, and DCFC and doesn't see a need to know
- Does not use an app to find chargers but plugs in when she finds one or already knows where one is; not tech-savvy and treats EV similar to a gas car

INTERACTION WITH A PUBLIC CHARGING STATION

- Is not willing to pay for charging
- If needed, she would prefer paying with a credit card rather than an app due to privacy sensitivity

TIME SPENT AT A PUBLIC CHARGING STATION

- Charging is not a top priority and plugs in if the charger is free and available at a location she is visiting anyway
- Facilities and amenities at public chargers do not affect her perception

PERSONA FINDINGS

Amy

White Businesswoman Who Drives a Work Truck and Could Potentially Buy an Electric Truck

OVERVIEW

Amy is an example of what a prospective EV owner would expect and need beyond the current EV infrastructure and systems. Current EV drivers tend to adapt to the infrastructure and systems that are available to them, and their expectations are constrained by the current situation. Amy, who uses a work truck as her primary vehicle and is a potential EV buyer, demonstrates how the market can prepare for the requirements of a commercial small business' EV.

Amy currently drives a Ford F-150. She views having an electric pickup truck as being a potential advertisement for industry of solar panel installation. Unlike bigger commercial establishments that tend to charge exclusively at their work bases, Amy would charge her truck at home and at public chargers as needed. Amy's requirement is for the battery range to last the entire workday, which appears plausible given the current trajectory of EV battery range. She expects the truck to be reliable and cannot change her driving patterns based on the availability of chargers. She expects to be part of the EV360 program in Austin because the program's fixed low monthly subscription costs would make her fuel expenses not only predictable but also significantly lower than her current fuel cost. This in turn would help reduce the overall cost of EV ownership, a significant factor in Amy's EV adoption decision. Austin's EV360 program could act as a role model for other cities and states in encouraging EV adoption.

Amy would plan to charge at home at the end of the workday, but if she needed to charge up before that, she would need to use a DCFC every time because any downtime during the day could result in lesser revenue earned. This would be in spite of fully understanding the implications of frequent use of DCFCs. She would prefer to have Wi-Fi at charging stations to improve productivity but would not want to wait any longer than she has to for charging the vehicle.

PERSONA FINDINGS: AMY

PERSONA DESCRIPTION

- 43-year-old female
- Drives a Ford F-150
- Lives in Austin, Texas
- Single
- General electrician/solar installer
- $150,000 business income
- Open to buying an EV, but nonavailability and her lifestyle don't currently support EV ownership
- Views EV ownership as an advertising element in line with her business
- Needs ability to plug in and use tools on-site
- Dreams of having a mini workshop in the truck bed, avoiding the need to travel back and forth to her workshop

TRAITS

TYPE OF CUSTOMER

- Views EV to be a potential advertisement element to her business
- Would need battery range to last the entire workday
- Is extremely range anxious because the truck is her livelihood and she depends on 100% uptime
- Travel habits are not expected to change in order to accommodate charging habits when owning an EV
- Goes on road trips with friends

RECHARGE HABITS

- Would charge overnight at home (Austin's EV360 program promotes free home charging)
- During the workday, would not have much downtime to use a public charger unless running out of range, and would always need a DCFC
- Would plug in while running errands as an advertisement for her business and would pay a reasonable cost to plug in even if she doesn't need to
- Fuel-cost conscious and would make use of subsidized/free home charging

CHOOSING A PARTICULAR CHARGING FACILITY

- Would only plug in if it's a long workday and she is running out of charge
- Would prefer a DCFC and would be willing to pay a reasonable premium to avoid downtime
- Would prefer to use the network for the card supplied with the truck upon purchase, but would switch providers if the network is unreliable
- Would prefer using a network with which she has an existing relationship, such as the company that installs her home charger

INTERACTION WITH A PUBLIC CHARGING STATION

- Would prefer being charged per kWh
- Prefers to use a seamless system to pay, such as charge cards, so that her receipts stay in one place for easy business expensing

TIME SPENT AT A PUBLIC CHARGING STATION

- Would prefer to be at a station that offers Wi-Fi and outlets to catch up on work
- Would like a drive-in with Wi-Fi while charging
- Would prefer not to wait any longer than she must for charging

CONCLUSIONS

This report discusses the behavior of today's EV drivers and their evolution over the past 10 years and into the next 10 years. Although best efforts were made to incorporate the latest and most accurate data in this study, the EV landscape has been changing rapidly and is continuing to do so.

Battery range has tripled since 2010, vehicle nameplates have increased from three to more than 20, and Level 2 charging locations have grown from approximately 1,000 to more than 70,000. This rapid development renders conducted research outdated very quickly.

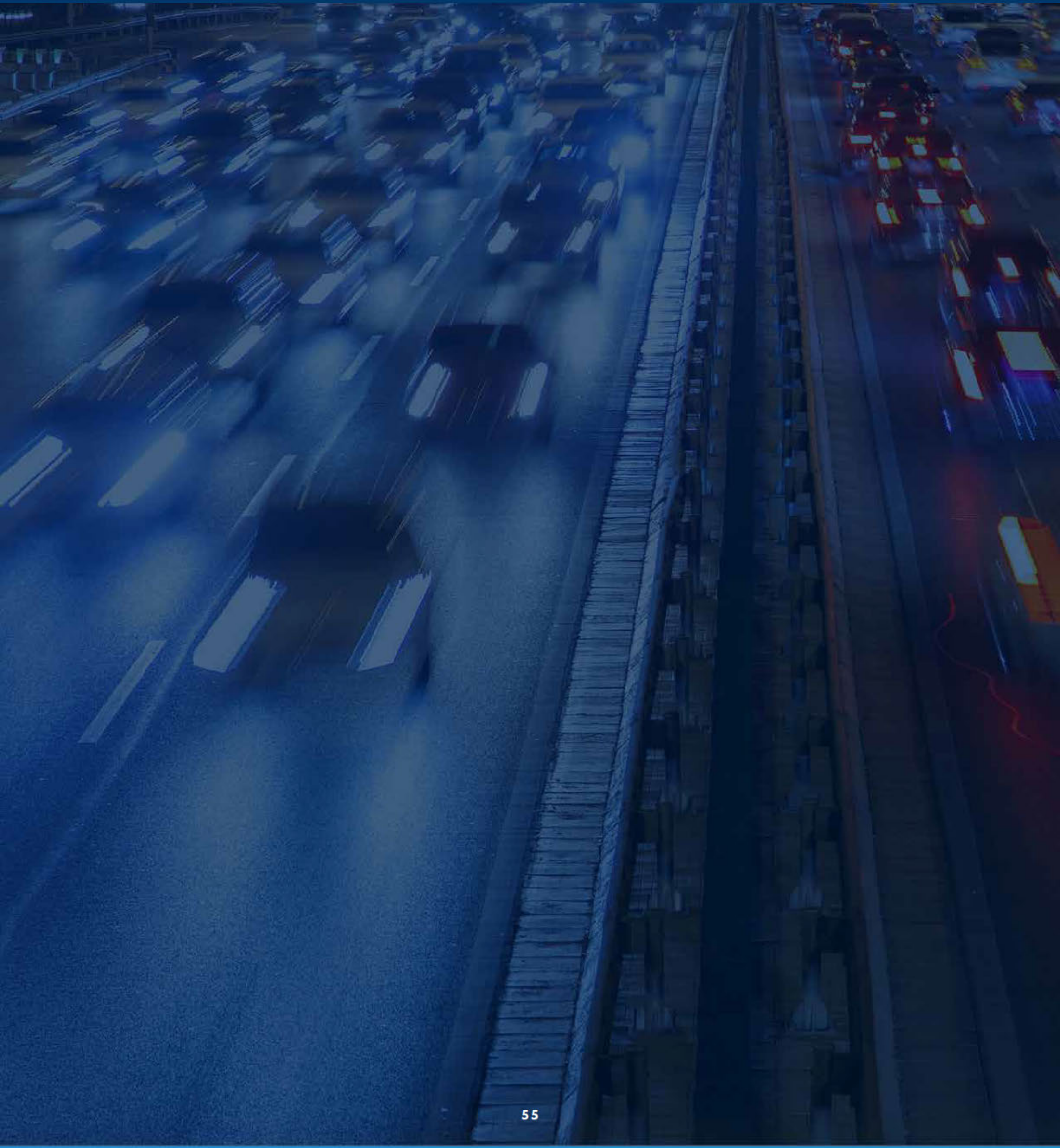
Technology has evolved, and the mindset of consumers has evolved to now view their EVs as a gadget that is not very different from their cellphone. The vast majority however are still concerned about the limitation of battery range, the need to plan ahead to charge their vehicle (unlike gasoline vehicles), and that battery degradation over time can limit their mobility. There is yet another group of the population that is not served by the current lineup of vehicles: People who want to buy a pickup truck or a minivan have very limited electric options, if any.

Travel habits of EV drivers today perhaps hide the deficiencies in the charging infrastructure amenities since they choose to purchase an EV knowing the infrastructure in place. This will change once EVs become more affordable, as more choice is available, as the charging infrastructure grows to instill confidence in range-anxious minds, and, most importantly, as the average driver's mindset changes to understand and embrace EV technology.

Understanding the mindset of today's drivers by means of studies helps make better, more informed choices in planning out infrastructure requirement for the future. Although many factors have a predictable trend, such as falling battery prices, improved range, and denser charging infrastructure, nuanced factors such as comfort of available infrastructure, features, and amenities that could influence a driver's decision to spend time at a charging station, recharging habits, and selection of chargers would continually be applicable for buyers who are not considering an EV purchase today but are likely to do so over the next few years.

Targeted surveys and interviews to capture near-term, mid-term, and long-term EV buyers' opinions with regards to the questions outlined in this report are necessary to ensure a robust view of how the charging infrastructure and surrounding amenities should involve. Additionally, direct feedback from EV manufacturers, charging station providers, fleet managers, and business entities such as grocery stores, shopping malls, highway stops, restaurant owners, park-and-rides, and other would be necessary to understand their plans to evolve the EV charging and consumer experience ecosystem. These items should be addressed in subsequent research.

APPENDIX



Abbreviations

BEV	battery electric vehicle
DCFC	direct current fast charger/charging
DOE	Department of Energy
EV	electric vehicle
EVSE	electric vehicle supply equipment
ICE	internal combustion engine
INL	Idaho National Laboratory
kWh	kilowatt-hour
NREL	National Renewable Energy Laboratory
OEM	original equipment manufacturer
PEV	plug-in electric vehicle
PHEV	plug-in hybrid electric vehicle
RFID	radio-frequency identification
SUV	sport utility vehicle
TCO	total cost of ownership
UCS	Union of Concerned Scientists
ZEV	zero-emission vehicle

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EVC ELECTRIC VEHICLE COUNCIL

About the Electric Vehicle Council

The Electric Vehicle Council is a non-advocacy organization whose mission is to coordinate the efforts of organizations actively engaged in supporting the deployment of EV charging infrastructure. The EV Council works to distribute existing research and education materials to amplify and enhance its value to the market, as well as conducts original research to fill gaps in knowledge and further educate interested stakeholders concerning the opportunities, challenges, and successful strategies associated with the installation and operation of EV charging stations.

For more information on the Electric Vehicle Council and a current list of members, please visit: fuelsinstitute.org/Councils/Electric-Vehicle-Council

About the Fuels Institute

The Fuels Institute, founded by NACS in 2013, is a 501(c)(4) non-profit research-oriented think tank dedicated to evaluating the market issues related to vehicles and the fuels that power them. By bringing together diverse stakeholders of the transportation and fuels markets, the Institute helps to identify opportunities and challenges associated with new technologies and to facilitate industry coordination to help ensure that consumers derive the greatest benefit.

The Fuels Institute commissions and publishes comprehensive, fact-based research projects that address the interests of the affected stakeholders. Such publications will help to inform both business owners considering long-term investment decisions and policymakers considering legislation and regulations affecting the market. Research is independent and unbiased, designed to answer questions, not advocate a specific outcome. Participants in the Fuels Institute are dedicated to promoting facts and providing decision makers with the most credible information possible so that the market can deliver the best in vehicle and fueling options to the consumer.

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Utility Rate Design

High Utility Fixed Charges Harm Low Income, Elders and Households of Color

Electric and natural gas utilities are undergoing sweeping change. Yet, home energy service remains a basic necessity of life. As utility industry technologies and economics change, rates, consumer protection policies, energy efficiency, and affordable payment programs must be designed to ensure that low-income home energy security is enhanced.

Because energy efficiency and distributed energy technologies, like rooftop solar, threaten utility companies' revenue, many utilities are clamoring to push through high mandatory fees on customers' bills. This is bad public policy. Rate design that focuses on fixed charges on all customers' bills that penalizes low-volume consumers within a rate class and undermines consumers' ability to control the cost of utility service through energy efficiency or conservation.

Principles of Good Rate Design

Utility rates should emphasize "volumetric" charges rather than flat, fixed charges and fees. Utility rates should be "inclining," so that higher usage levels at charged at higher rates. Good rate design should always be coupled with:

- Whole-house low-income energy efficiency programming
- Affordable payments and arrearage management for low-income households

- Effective consumer protections shielding vulnerable customers from loss of vital home energy services

NCLC Research on Residential Energy Consumption

National Consumer Law Center's research and analysis, based on the 2009 U.S. Energy Information Administration's Residential Energy Consumption Survey (the latest data available), shows that, on average, households with lower incomes, and who are African American, Latino, or older, use less electricity and natural gas than higher-income households. "Fixed charge rate design" unfairly and disproportionately harms these customers. Because it undermines energy efficiency incentives, it is also bad for the environment.

Click on a state or region for median average electricity consumption among households by income category, race/ethnicity, and age.

All Regions – 150% Poverty Status

For state and regional data and an interactive map, click here.

Related Resources

- Press Release: Appalachian, Wheeling Power Companies Proposal Will Cause Significant Rate Increases for Low-Income West Virginians; Comments, Sept. 24, 2021
- Report: Recovery of Utility Fixed Costs: Utility, Consumer, Environmental and Economist Perspectives by John Howat (NCLC), Ralph Cavanagh (NRDC), Severin Borenstein (UC-Berkeley); editor: Lisa Schwartz, Lawrence Berkeley National Laboratory, June 2016

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Use Less, Save More: Adding a Conservation Incentive to Percentage of Income Payment Programs

Janine Migden-Ostrander

On April 13, 2021

Filter

For low-income households, being able to afford utility service is a constant struggle. The average American household spends 2-3% of its income on its energy bills, but for a low-income family, the energy burden can be more like 15-20% (or higher). Customers may have to decide whether to put money toward utility bills, to avoid a disconnection, versus paying for food, rent or medicines — difficult choices when all of these items are necessities. Policies are needed to ensure that vulnerable populations do not have to forego vital utility service. One policy used in several states, the percentage of income payment plan (PIPP), can help low-income households keep the lights on, but may not provide an incentive to conserve. Reforms to PIPP programs can preserve affordability while encouraging customers to save energy.

How PIPP works

Ohio was the first state to launch a PIPP program, in the 1980s, to address utility affordability concerns; similar mechanisms have since been adopted in other states like Illinois and Pennsylvania. In each state the details may vary; however, the basic premise is that eligible low-income customers pay a percentage of their income towards electric and gas service, rather than paying the full monthly bill. Ohio sets this percentage at 6% of household income for each utility bill (gas and electric), and Illinois sets it at 3% of income for each bill. Customers who have combined gas and electric service offered by one utility or have electric heat pay 10% of their household income total. Eligibility can be determined by the individual state or utility implementing the program. In Ohio, eligible customers have household income at or below 150% of the federal poverty guideline (FPG). Customers will not be disconnected so long as they make PIPP payments.

The under-payment, the difference between the full bill and the customer's PIPP payment amount, is recovered via a charge to all customers. In Ohio, a PIPP rider is added to all customer bills (residential, commercial and industrial) to compensate the utility. Arrearages may also be collected in the event that a customer's household income increases beyond eligibility for PIPP; in that event, the customer becomes responsible for paying back remaining money owed through a long-term payment plan. Some programs may include a debt forgiveness feature such that for each month a payment is made, a month of arrearage payments is forgiven. In Illinois, for example, customers who make an on-time regular payment receive a one-twelfth reduction in total arrearages. The goal is to give the customer an incentive to pay down their debt in a more manageable way and to be able to see the light at the end of the tunnel. All arrearage payments are deposited into the PIPP collection account and credited against the PIPP surcharge.

How to give PIPP customers an incentive to conserve

One flaw of this program is that tying payments to income instead of usage provides no incentive to conserve. A PIPP customer will pay the same bill amount whether using 600 kWh or 1,000 kWh. This can result in higher energy bills, which at the same time increases the PIPP surcharge and the amount of the debt owed if and when a customer graduates from PIPP. One option to address this concern is to create a conservation incentive so that some of the savings from reduced usage are passed on to the customer. For example, the utility could create a baseline of usage for a dwelling based on historical monthly data for that dwelling over the past three to five years. To the extent that a PIPP customer conserves and uses less than the baseline, adjusted for weather, the monetized value of the energy savings would be split between the utility and the customer through a reduction in that customer's monthly bill. While some may argue that the conservation savings should go to lower the overall arrearage, doing so would not incentivize the customer to reduce usage nearly as much. These customers are struggling on a daily basis and need the savings now, not at some uncertain time in the future.

Below is a hypothetical illustration of how adding a conservation incentive would work.

TRADITIONAL PIPP MECHANISM	
Customer monthly income	$1,500
Customer payment (6% of income)	$90
Customer bill [$10 customer charge + (1,000 kWh x $.12/kWh)]	$130
Customer arrearage amount collected through surcharge (bill amount of $130 minus customer payment of $90)	$40

PIPP MECHANISM WITH CONSERVATION INCENTIVE	
Customer monthly income	$1,500
Customer payment (6% of income)	$90
Customer historical bill [$10 customer charge + (1,000 kWh x $.12/kWh)]	$130
Customer current bill with incentive mechanism [$10 customer charge + (900 kWh x $.12)]	$118
Value of savings due to conservation (1,000 kWh minus 900 kWh = 100 kWh x $.12)	$12
Customer share of savings on bill ($12 x $.50)	$6
Customer total bill ($90 minus $6)	$84
Customer arrearage amount collected through surcharge (bill amount of $118 minus customer payment of $84)	$34
Reduction in PIPP collection account ($40 minus $34)	$6

This hypothetical uses the 6% income payment requirement under the Ohio program and assumes eligibility at 150% of the FPG. The amount of savings and the reduction in the customer's arrearage account may vary based on the details of a state's PIPP program.

Note that the additional conservation savings would be voluntary and there would be no penalty for not participating or reducing consumption. Indeed, in some households, reducing consumption may not be possible — though it could be made so by encouraging participation in energy efficiency and weatherization programs for low-income customers. This would increase the savings in the years immediately following the efficiency or weatherization improvements and would provide a further incentive for PIPP customer participation in these programs.

Non-PIPP customers would also benefit from conservation by PIPP customers, as noted in the table above. Since the charge to non-PIPP customers is what pays the difference between actual bills and PIPP payment amounts, any reduction in electricity usage will reduce the overall arrearage account and the amount paid by all other customers via the bill rider. For all customers but especially for customers whose incomes are low to moderate but not low enough to qualify them for PIPP (for example, those whose incomes fall into the range of 151–200% of the FPG), a reduction in the monthly surcharge would be welcomed.

Thus, this conservation adder creates multi-layered benefits. It reduces the amount that the PIPP customer must pay in a given month, freeing up badly needed dollars to cover other necessities; it reduces the amount of subsidies paid by other customers; and it reduces consumption and the pollution that comes with it. Injecting a non-punitive conservation incentive into the PIPP program would help advance energy efficiency, while also providing benefits to vulnerable populations. It would also reduce our carbon footprint and lower bills for all utility customers, regardless of whether they are enrolled in PIPP.

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European policymakers and car manufacturers are increasingly committing to the phaseout of internal combustion engine vehicles. With this shift to electric transport, tariffs and services for so-called smart charging of EVs bring significant value to consumers and the power sector. Now is the time to build a robust regulatory framework to expand the markets for...

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Rebuttal Testimony

August 11, 2022

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

A. My name is Steve Storm. I am a Senior Economist employed in the Rates, Finance, and Audit 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. I sponsored Exhibit Staff/1700 in Staff's Opening Testimony.

Q. What is the purpose of your Rebuttal Testimony?

A. My Rebuttal Testimony discusses testimony of Intervening Parties regarding issues included in my Opening Testimony. It also discusses PacifiCorp's response to my testimony in the Company's Reply Testimony.

Q. Did you prepare any exhibits for this Rebuttal Testimony?

A. No.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Wildfire Mitigation and Vegetation Management Mechanisms 2
Issue 2. Amortization of COVID-19 Deferrals and Rate Spread 24
Issue 3. Pensions and Post-Retirement Medical 30
Issue 4. Multi-State Process 34
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ISSUE 1. WILDFIRE MITIGATION AND VEGETATION MANAGEMENT MECHANISMS

Q. Which intervening Parties included discussion of issues related to PacifiCorp's recovery of wildfire mitigation and vegetation management costs in Opening Testimony?

A. While the Alliance of Wester Energy Consumers (AWEC), the Citizens' Utility Board of Oregon (CUB), and the Klamath Waters Users Association and Oregon Farm Bureau Federation (KWUA-OFBF) discuss aspects of wildfire mitigation or vegetation management, none of these Parties discussed cost recovery mechanisms in their respective Opening Testimony. The Northwest and Intermountain Power Producers Coalition (NIPPC), the Small Business Utility Advocates (SBUA), Vitesse, and Walmart did not discuss any aspect of wildfire mitigation or vegetation management in their respective Opening Testimonies.

Q. What are the Commission's goals regarding cost recovery of prudent investments and reasonable expenses incurred for wildfire mitigation and vegetation management?

A. The Commission has previously recognized "the urgency of addressing the safety of the communities served by and surrounding PacifiCorp's facilities" and its objective "to fairly balance the costs and risks associated with responding to changing wildfire risk between shareholders and utility customers."[1] The Commission has observed that "[v]egetation management is a critical safety measure, and meeting the Commission's minimum standards for vegetation management should be the baseline, with zero violations as the ultimate goal."[2] The Commission has also noted PacifiCorp's "stated intent to dramatically decrease the vegetation clearance violations over the three-year period (2021-2023)."[3]

Q. What did PacifiCorp recommend to the Commission in Reply Testimony?

A. The Company provided a summary of its wildfire mitigation and vegetation management recommendations in Reply Testimony.[4] The following is my recap of these recommendations:

- Reflect the $20 million associated with WPP implementation in 2023 in base rates, with recovery for incremental WPP costs through the Company's proposed SB 762 AAC, Schedule 190 (Commission Docket No. UE 407).
- Reflect the full amount of the balance of the Company's vegetation management costs ($50 million) in base rates, without Staff's proposed disallowance of costs based on the growth of Oregon costs relative to other states, and without a ten percent "holdback" subject to the WMVM.

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1 *In the Matter of PacifiCorp, Request for General Rate Revision,* Docket UE 374, Order No. 20-473 at pages 120-121.
2 Order No. 20-473 at page 124.
3 Page 121 of Order No. 20-473 in UE 374, citing Exhibits Staff/2702, Moore/1 and PAC/2900, Lucas/18-20 in that proceeding.
4 Exhibit PAC/1200, Steward/13-14.

- Require PacifiCorp to track and report its expenditures and defer unspent dollars.
- Reset (increase) the thresholds in the WMVM for 2022 and 2023 to reflect that PacifiCorp is transitioning to a more accelerated vegetation management cycle (from four years to three years, starting in 2022) and seeks a transition period to get to "steady state" violation levels.
- Apply the WMVM through the transition period (end of 2024) by counting violations only in areas that have been trimmed under the three-year cycle program.
- Replace the earnings thresholds in the WMVM with a sharing mechanism for costs incremental to those included in base rates.

Q. What is the WPP and what is the WMVM?

A. PacifiCorp identifies its Wildfire Mitigation Plan (WMP) as its Wildfire Protection Plan (WPP), and the Commission has recognized that a WPP is the same as a WMP, with either referring "to the document filed with the Commission relating to an electric utility's risk-based plan designed to protect public safety, reduce the risk of utility facilities causing wildfires, reduce risk to utility customers, and promote electric system resilience to wildfire damage."[5,6] Oregon's Senate Bill (SB) 762 required investor-owned utilities to file risk-based wildfire mitigation and protection plans (WPP) by December 31, 2021.[7]

[5] See Oregon Administrative Rule 860-300-0010(11), defining "wildfire mitigation plan."
[6] Staff provides certain characteristics of a WPP at Exhibit Staff/1300, Moore/3 at lines 2-6.
[7] Id., page 2.

The WMVM is the Wildfire Mitigation Vegetation Management cost recovery mechanism adopted by the Commission as an outcome of PacifiCorp's most recently completed general rate case proceeding, docketed as UE 374.[8]

Q. Has PacifiCorp filed an application for an automatic adjustment clause (AAC) for recovery of costs related to implementation of its WPP?

A. Yes. As noted by the Company, it filed its application on July 12, 2022.[9] This filing has been docketed as UE 407 and designated a contested case. Chief Administrative Law Judge (ALJ) Nolan Moser suspended PacifiCorp's filing for investigation for as many as nine months from August 24, 2022.

Q. For WPP costs in what year is PacifiCorp proposing recovery in its UE 407 application?

A. I understand these to be prospective 2022 expenditures based on PacifiCorp's application.[10] The Commission previously approved PacifiCorp's application for use of deferred accounting for operating costs and capital investments made to implement and operate the Company's WPP. This was for the 12-month period beginning on January 5, 2022.[11]

Q. What is an anticipated rate effective date in UE 407?

A. A prehearing conference in UE 407 has not been held as of the time this testimony is being prepared. However, the filing has been suspended for nine

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8 Order No. 20-473 at pages 120-125.
9 PAC/1200, Steward/15, including footnote 14.
10 Pages 2-3 of PacifiCorp's July 12, 2022, application in UE 407.
11 Page 1 of the Staff Report attached as Appendix A to Order No. 22-258 in Docket No. UM 2221.

months, and therefore I would anticipate a rate effective date in the second quarter of 2023, if the filing is approved by the Commission.

Q. Did PacifiCorp provide a detailed description of its cost recovery mechanism in the Company's UE 407 application?

A. No. I assume the Company's testimony to be filed in UE 407 will provide a detailed description of its proposed cost recovery mechanism.

Q. Regarding the bullet points in PacifiCorp's summary of wildfire mitigation and vegetation management recommendations provided above, are there any with which you agree?

A. Yes. Additionally, and regarding issues on which Staff and the Company disagree, Staff is always willing to engage with the Company and interested Parties in constructive discussions regarding general rate case issues, such as the WMVM mechanism and a proposed WPP cost recovery mechanism and will participate in a near-term (as of the time this testimony was being prepared) conference regarding the WMVM mechanism with PacifiCorp and interested Parties.

I fully agree with PacifiCorp's recommendation that the Company be required to track and report its expenditures on wildfire mitigation and vegetation management costs, reporting both capital investments and expense. I additionally recommend that PacifiCorp's reporting include the periodic budget amount for each category of expenditure. I agree that PacifiCorp should either return deferred amounts that are unspent to customers,[12] or hold them for later disbursement, with that decision made by the Commission. The decision of whether to return the monies to customers or use them in a subsequent year could be a decision that is made in each year of the mechanism.

Q. Please discuss why you disagree with the second bullet point above outlining PacifiCorp's position, which is the Company's proposal to "[r]eflect the full amount of the balance of the Company's vegetation management costs ($50 million) in base rates, without an arbitrary disallowance of costs based on the growth of Oregon costs relative to other states, and without a 10 percent 'holdback' subject to the WMVM."[13]

A. For clarity, I first identify the amounts PacifiCorp has requested for wildfire mitigation and vegetation management in this proceeding. As documented by Staff, the total amount for these two activities is $70.8 million.[14] Of this amount, $50.4 million is associated with vegetation management expense and $19.7 million with wildfire mitigation expense.[15] The Company has also proposed $45.1 million for capital investment in wildfire mitigation.[16]

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[12] Exhibit PAC/1200, Steward/20, lines 1-7.

[13] Exhibit PAC/1200, Steward/13.

[14] Table at Exhibit Staff/1300, Moore/6. PacifiCorp corroborates this $70.8 million total requested value at PAC/1600, Berreth/2. Amounts in this discussion are on either a *situs* or Oregon-allocated basis.

[15] Table 1 of PacifiCorp's response to Staff data request 466, which is included at Exhibit Staff/1302, Moore/2. The $70.1 million total of $50.4 and $19.7 million represents an embedded $0.7 million discrepancy between these values, all of which have been provided by PacifiCorp.

[16] Id.

Q. PacifiCorp implies that Staff has included WPP-related costs in its proposed WMVM "holdback."[17] Please identify the WPP expenses that PacifiCorp has proposed for recovery in UE 399.

A. PacifiCorp identified $50.4 million for 2023 WPP vegetation management expense and $19.7 million for 2023 WPP wildfire mitigation expense in response to Staff data request 466.[18]

Q. As PacifiCorp has identified the expense amounts above as WPP expenses, have you included WPP-related costs in the "holdback?"

A. Yes. I do include WPP-related costs in the "holdback" amount and discuss below the reasons for doing so.

Q. Is the Company entitled to dollar-for-dollar recovery of any of the wildfire mitigation or vegetation management costs, including WPP costs?

A. While I am not an attorney, my understanding is that the Company is not entitled to dollar-for-dollar recovery of such costs, including the WPP costs. My attorneys will address this issue in briefing.

Q. Did the Commission authorize the annual deferral of costs within the WMVM mechanism?

A. Yes. The Commission found that "annual recovery of prudently incurred costs for vegetation management and wildfire mitigation, tied to demonstrated improvements to the company's vegetation management practices,

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17 Exhibit PAC/1200, Steward//18 line 3: "First, is it appropriate to include WPP-related costs in a WMVM 'holdback?'"

18 Tables 1 and 2 in PacifiCorp's response to Staff data request 466.

appropriately matches the costs borne by and benefits received by ratepayers."[19]

Q. What do you see as a reasonable augmentation of the existing WMVM mechanism in support of the Commission's objectives?

A. My primary recommendation is to maintain the current form of the WMVM cost recovery mechanism, including the holdback, and to continue the three-year term of the mechanism adopted in UE 374 as well as recognize that the Company continues to perform poorly with respect to number of vegetation management violations.[20] Therefore, I recommend a "holdback" of ten percent, equating to $6.4 million of the proposed $70.8 million expense after a $6.5 million downward adjustment recommended by Staff in Opening Testimony,[21] which represents an appropriate amount for the Company to have at risk, subject to performance criteria such as the levels of violations observed in Staff's annual audit. This implies, for a vegetation management total expense of $50.4 million, a "holdback" of approximately $5.0 million[22] on a pro rata basis as a result of this proceeding. It implies, for a wildfire mitigation total expense of $19.7 million, a "holdback" of approximately $2.0 million on a pro rata basis.[23]

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[19] Id., at page 120.
[20] See, e.g., Exhibit Staff/1705, esp. Storm//5.
[21] Exhibit Staff/6, Moore/6 and Exhibit Staff/2800.
[22] Both values are prior to any allocation of the $6.5 million reduction in wildfire mitigation and vegetation management expense Staff recommends.
[23] Note that Staff uses, in direct testimony at Staff/1300, the total expense proposed by PacifiCorp for vegetation management and wildfire mitigation, which is $70.8 million from PacifiCorp's response to Staff data request 467, while the $70.1 million sum (of the $50.4 and $19.7 million values) here is from PacifiCorp's response to Staff data request 466 and differs by $0.7 million.

I note that a “holdback” of 10 percent of the annual costs in rates associated with wildfire mitigation capital expenditures resulting from this proceeding, representing the revenue requirement associated with the annual amounts of return on and of the proposed $45.1 million total capital investments in wildfire mitigation[24] is an amount I consider adequate to serve as an appropriate performance incentive associated with PacifiCorp’s full recovery of these expenditures.

Q. PacifiCorp requests that $20 million associated with WPP implementation in 2023 be included in base rates resulting from UE 399, with recovery for incremental WPP costs through the Company’s proposed SB 762 AAC, Schedule 190. Please discuss this amount.

A. I am unclear regarding the nature and origin of this $20 million *for WPP implementation in 2023*. PacifiCorp identifies an incremental $19.9 million for WPP implementation in 2022, but states that this forecasted amount is proposed for recovery in the mechanism resulting from UE 407.[25] I note that PacifiCorp’s response to Staff data request 466 identifies a total of $19.7 million in 2023 WPP expense for wildfire mitigation, not WPP implementation. PacifiCorp asserts that SB 762 “specifically addresses cost recovery for WPP implementation through an AAC or other method to allow timely recovery.”[26] Additionally, “the Company continues to propose that

[24] PacifiCorp’s response to Staff data request 466. There are no capital investments proposed for vegetation management in 2023.
[25] Exhibit PAC/1200, Steward/15.
[26] Id., page 16.

incremental WPP implementation costs be collected through an ACC" and not through the WMVM mechanism.[27]

Q. What do you recommend regarding this $20 million in 2023 expense for WPP implementation called out by PacifiCorp?

A. Because rates will reflect expenses in the 2023 test year, I could support including these amounts in UE 399 rates. Alternatively, this amount could be reserved for consideration in UE 407.

Q. What is your position regarding how and where the $19.7 million in 2023 wildfire mitigation expense should be recovered?

A. I have the same recommendations I have for WPP implementation expenses.

Q. What does this imply for the amount of "holdback" in this proceeding?

A. Please see Table 2500-1, which illustrates pro rata adjustments for the discrepancy noted in a previous footnote and for Staff's recommended adjustment to the requested total of $70.8 million.

[27] Id., lines 1-4.

Table 2500-1: Vegetation Management and Wildfire Mitigation Amounts in Staff Testimony ($Millions)

		With Pro Rate of Discrepancy	With Staff Adjustment (Staff/2800)	With Pro Rate of Staff Adjustment	Holdback Amounts	Amounts in Rates[28]
Veg. Management	50.4	50.9	50.9	46.2	4.6	41.6
Wildfire Mitigation	19.7	19.9	19.9	18.1	1.8	16.3
Discrepancy	0.7					
Staff Adjustment			(6.5)			
Total	70.8	70.8	64.3	64.3	6.4	57.9

The total holdback, before an adjustment described below, would be $6.4 million, based on the total of the $50.4 million for vegetation management and the $19.7 million for wildfire mitigation and impact of two Staff adjustments. The first adjustment is a *pro rata* adjustment for the $0.7 million discrepancy in PacifiCorp-supplied values noted in a previous footnote. The second adjustment is a *pro rata* adjustment for Staff's recommended $6.5 million downward adjustment to the $70.8 million total, resulting in a total of $64.3 million.[29] Table 2500-1 shows each of these two adjustments.

The total holdback in this proceeding is $6.4 million. Alternatively, if the Commission wants to reserve the specified amounts above associated with 2023 spending, the "holdback" would be $4.6 million for vegetation management expense and $1.8 million for wildfire mitigation.

Q. What does this imply for cost recovery in UE 399 base rates?

28 The $41.6 million for vegetation management is recovered in the WMVM mechanism, while the $16.3 million for wildfire mitigation is recovered in base rates.

29 Staff/1300, Moore/6 and Staff/2800.

A. Recovery in UE 399 base rates is $57.9 million in the primary recommendation or, in the alternative, 90 percent of $46.2 million, or $41.6 million, for the 90 percent of vegetation management expense that is not held back. The alternate has no recovery in UE 399 base rates for the $16.3 million, equaling 90 percent of $18.1 million amount for wildfire mitigation expense that results after applying the two adjustments to the original $19.7 million described above.

Q. What does this imply for UE 399 expenses in your alternative case?

A. Expenses to be recovered in UE 399 rates are adjusted downward by $4.6 million for the 10 percent "holdback" amount to be recovered in the WMVM mechanism.

Q. Did Staff include this downward expense adjustment in Opening Testimony?

A. No.

Q. PacifiCorp recommends increasing the level of thresholds in the WMVM mechanism "to reflect that PacifiCorp is transitioning to a more accelerated vegetation management cycle (from four years to three years, starting in 2022) and needs a transition period to get to "steady state violation levels."[30]

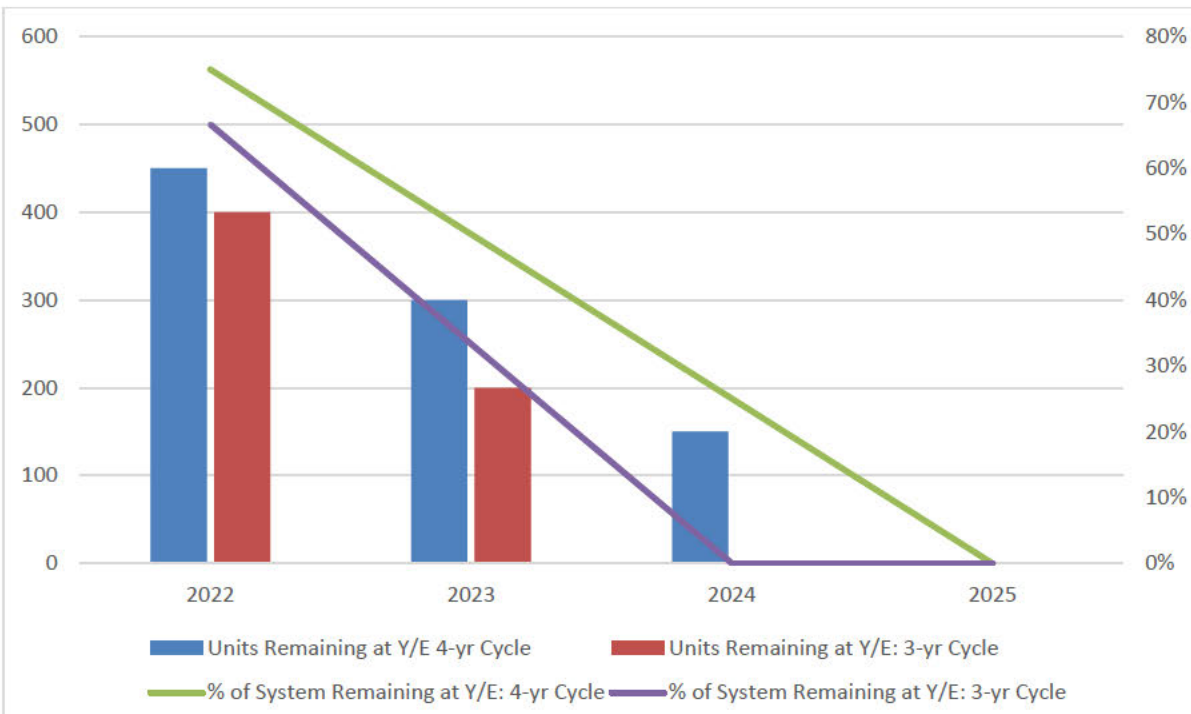
A. I start from the premise that the threshold levels resulting from the UE 374 proceeding were and are appropriate for a four-year trim cycle, as that was the

[30] Exhibit PAC/1200, Steward/13-14. See also the discussion at PAC/1600, Berreth/5 line 1 through Berreth/6 line 17.

cycle in place when the Commission ordered the application of performance metrics for recovery of the "holdback" amount in UE 374.[31]

Given this premise, PacifiCorp's proposal of an *upward* adjustment to threshold levels in the three-year transition period from a four-year cycle to a three-year cycle, has it exactly backwards. I demonstrate this in Figure 2500-1 using a 600-unit system, where the units are a measure of what has to be "trimmed" within a four or three-year cycle.

Figure 2500-1: Units Remaining and Percent of Units Remaining at Year-end in 600 Unit System



Q. Please explain Figure 2500-1.

A. Figure 2500-1 represents aspects of a hypothetical 600-unit system requiring vegetation management ("trimming") of all units during either a four-year cycle

[31] Order No. 20-473, Docket UE 374, at pages 121-122.

or a three-year cycle, with each cycle beginning in 2022; i.e., if there is a change from a four-year cycle beginning in 2022, the transition from the four-year cycle to the new three-year cycle is completed as of year-end 2024.

The *blue* columns represent the number of units remaining to be trimmed at year-end under a four-year cycle, which ranges from 600 remaining units (the entire system) at the beginning of 2022 (not shown) to 450 remaining units at year-end 2022 (represented by the left-most *blue* column) to 300 remaining units at year-end 2023 to 150 remaining units at year-end 2024 (represented by the right-most *blue* column), to zero remaining units at year-end 2025 at the end of the four-year cycle. The annual reduction in remaining units reflects that 25 percent of the total system units, or 150 units, are trimmed on an annual basis.

Analogously, the *red* columns represent units remaining to be trimmed at year-end in the three-year cycle, where 33.3 percent of the system, or 200 units, is trimmed each year for three years.

Similarly, the *green* line represents the percent of the system's units remaining to be trimmed at year-end under the four-year cycle and the *purple* line represents the percent of the system's units remaining to be trimmed under the three-year cycle.

Q. Please explain how "PacifiCorp has it backwards."

A. This is because more of the system is trimmed annually under the three-year cycle beginning with the transition to a three-year cycle in 2022. This is shown by both the *red* columns being less than the *blue* columns for every year (including 2022) and the *purple* line being less than the *green* line for every year (including 2022). As more of the system is trimmed both annually and cumulatively under the three-year cycle than under the four-year cycle, the number of remaining untrimmed units is smaller every year in the three-year cycle, and the annual audit of a system that has fewer untrimmed units would be expected to yield fewer violations, not more violations as PacifiCorp would have it. A corollary to this is that during the transition from a four-year cycle to a three-year cycle, a given level of violations should be easier to not surpass—and not more difficult—than under an ongoing four-year cycle, and for every year of a three-year transition period.

Q. What do you recommend regarding threshold levels of violations?

A. I recommend there be no change to the threshold levels authorized in UE 374, as shortening the cycle time is a PacifiCorp action taken to reduce the number of observed violations, albeit at greater expense. However, it is important to understand that a given level of observed violations is more easily attained both during the transition from a four-year cycle to a three-year cycle and also under an ongoing three-year cycle.

I also think it is important to note that the threshold violation levels are based on PacifiCorp's historical performance. PacifiCorp was able to achieve satisfactory performance for several years.[32] Now that PacifiCorp's performance has been not as good as in the past, PacifiCorp requests its "grading scale" be relaxed so it is no longer viewed as underperforming.

32 See the chart of historical observed violations at Exhibit Staff/1705, Storm/5.

PacifiCorp has no justification for relaxing its performance benchmarks other than those proposed are being used by PGE. However, the service territories for PacifiCorp and PGE are different and there is no reason to think they both should have the numerically same violation level thresholds.

Q. PacifiCorp asserts that more trees are drying out and becoming subject to greater infestation, which increases the number of observed violations. What are your thoughts on this?

A. This may be true, but PacifiCorp provides no support for its assertion. While this may provide support for a three-year versus four-year cycle, it does not support a three-year cycle having more violations than a four-year cycle.

Q. PacifiCorp proposes to count violations only in areas that have been trimmed during the transition period 2022-2024 from a four-year cycle to a three-year cycle. How do you respond?

A. I see no merit to this PacifiCorp proposal and strongly recommend against it. As we saw above, an audit of the entire system is less likely to yield a given level of violations both during the transition period and under an ongoing three-year cycle than under a four-year cycle. Additionally, and as stated in my Opening Testimony,[33] PacifiCorp's performance has degraded, and it seems unreasonable to reward bad outcomes in the first year of a three-year trial period for the WMVM mechanism by revising the mechanism to more favorable terms to the Company. The issue is not a standard of effectiveness of tree-trimming, the standard is the number of violations. PacifiCorp customers

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[33] Exhibit Staff/1700, Storm/63.

in Southern Oregon will not feel secure knowing that other PacifiCorp service areas are well-trimmed. That will not prevent fires or poor service in Southern Oregon. Therefore, we should not have a mechanism based on audits (and violations) that focus on areas that have been more recently trimmed.

Q. Your recommendations either have been or will likely be unsatisfactory to PacifiCorp. Do you have any final words regarding cost recovery and the WMVM mechanism?

A. Yes. PacifiCorp previously stated intent, as above, is to ‘dramatically decrease the vegetation clearance violations over the three-year period (2021-2023).”[34] Yet, in this proceeding, the Company has or likely will oppose Staff’s recommendations, which provide a clear (and potentially dear) incentive towards achieving this result. Instead, PacifiCorp proposes a number of changes which make avoiding consequences under the mechanism appreciably easier. As discussed above, these include OPUC audits of only the most recently trimmed portions of the system. Also included are upward adjustments in threshold levels where—if any adjustments should be made in the transition period from a four-year trim cycle to a three-year trim cycle—they are logically *downward* adjustments, as demonstrated by my hypothetical example above.

I note that PacifiCorp is now in the middle of the 2021-2023 period in which they are to achieve “dramatic decreases” in vegetation management

[34] Page 121 of Order No. 20-473 in UE 374, citing Exhibits Staff/2702, Moore/1 and PAC/2900, Lucas/18-20 in that proceeding.

violations. I believe PacifiCorp must have more at risk than under the status quo mechanism. I also believe that the incentives that result from implementation of the Company's recommendations will not provide a sufficient incentive for "dramatic decreases" in violations within the contemplated timeframe.

I also want to note that it is possible, through collaborative discussions among interested parties, we may be able to reach a resolution such that Staff could revise its primary recommendation to continue with the design of the current mechanism for the two remaining years. Staff is open to such discussions and hope they occur.

Q. Have you prepared a table comparing the WMVM mechanism incorporating PacifiCorp's recommended changes and the mechanism with your recommended changes?

A. Yes. I include this as Table 2500-2, where dollar amounts are those proposed in UE 399. Staff's values reflect the $6.5 million downward adjustment to the $70.8 million proposed by PacifiCorp.[35]

Staff's recommended changes to the WMVM mechanism do not include changes to the violation thresholds or levels from those in the current version. The current version of the WMVM mechanism applies an earnings test for amounts between $30 million and $36.645 million (with no earnings test to be applied to an actual amount in this range if violations are below the Level I

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[35] See Exhibits Staff/1300 and Staff/2800.

threshold of 75). Amounts exceeding $36.645 are not subject to an earnings test within the mechanism.

Table 2500-2: UE 399 Proposed WMVM Mechanism ($Millions)

Item	PacifiCorp	Staff Primary	Staff Alternate
Amount of Expense included in Base Rates	$50.4 veg mgmt $19.7 wildfire mitigation $ 0.7 discrepancy $70.8 total	$41.6 veg mgmt. $16.3 wildfire mitigation $57.9 total	$41.6 veg mgmt
Expense included in WMVM mechanism not subject to an earnings test			$16.3 wildfire mitigation
Amounts Subject to Violation Standards	veg mgmt Overages only	$4.6 veg mgmt $1.8 wildfire mitigation $6.4 Holdback + Prudent Overages in veg mgmt & wildfire mitigation	$4.6 veg mgmt $1.8 wildfire mitigation $6.4 Holdback + Prudent Overages in veg mgmt & wildfire mitigation
Meaning of Violation Thresholds	Impacts Sharing Percent for veg. mgmt above $50	Impacts Amounts Recovered (subject to earnings test?)	Impacts Amounts Recovered (subject to earnings test?)
Violation Level I Threshold	0-150 Vs: No Sharing ($50 - $58)	0-74 Vs: No earnings test (Holdback(s) + Prudent Overages)	0-74 Vs: No earnings test (Holdback(s) + Prudent Overages)
Violation Level II Threshold	151-300 Vs: 95/5 ($50 - $58)	75-149 Vs: Earnings Test @ AROE less 100 bps (Holdback(s) + Prudent Overages)	75-149 Vs: Earnings Test @ AROE less 100 bps (Holdback(s) + Prudent Overages)
Violation Level III Threshold	301 – 500 Vs: 90/10 ($50 - $58)	150-200 Vs: Earnings Test @ AROE less 150 bps (Holdback(s) + Prudent Overages)	150-200 Vs: Earnings Test @ AROE less 150 bps (Holdback(s) + Prudent Overages)
Above Level III Threshold	>500 Vs: 80/20 ($50 - $58)	>200 Vs.: Earnings Test @ AROE less 200 bps (Holdback(s) + Prudent Overages)	>200 Vs.: Earnings Test @ AROE less 200 bps (Holdback(s) + Prudent Overages)
Amounts greater the $58	0-74 Vs: No Sharing	Not Applicable	Not Applicable
Amounts greater than $58	>74 Vs: 50/50	Not Applicable	Not Applicable
Violation Metric	"Verifiable" Observed Violations on lines trimmed within past 2 years	Number of Observed Violations + Unresolved Prior Violations not observed in current audit	Number of Observed Violations + Unresolved Prior Violations not observed in current audit
Other Recovery Limitations	Full recovery of costs	Number of Observed Violations + Unresolved Prior Violations not observed in current audit	Number of Observed Violations + Unresolved Prior Violations not observed in current audit

Q. PacifiCorp proposed a sharing mechanism to replace the WMVM mechanism in Direct Testimony.[36] Has your thinking evolved regarding this proposal?

A. It may have evolved somewhat. While I prefer the WMVM mechanism, with the changes I recommend, it may be possible for Staff to support a sharing mechanism.

Q. What aspects of PacifiCorp's proposed sharing mechanism do you recommend the Commission reject?

A. As illustrated in Table 3 at Exhibit PAC/700, Berreth/29, I recommend against a mechanism where sharing is based on different levels of expense. More palatable are sharing bands that apply to all prudent amounts of expense proposed for recovery. As a starting place for discussion and Commission consideration, Staff identifies the structure of a mechanism in Table 2500-3 as a starting place, where expenses above those in base rates resulting from UE 399 are those Staff recommends the Commission find prudent. In this alternative, there would not be the holdback of monies discussed earlier but this alternative would apply to total vegetation management and wildfire mitigation expenses.

[36] See Table 3 in Exhibit PAC/700, Berreth/29.

Table 2500-3: Structure of a Sharing Mechanism

Amounts to be Recovered	Number of Violations	Sharing Band (Customers/Company)
All amounts above that in Base Rates	0 - 74	None
All amounts above that in Base Rates	75 – 149	95/5
All amounts above that in Base Rates	150 - 199	90/10
All amounts above that in Base Rates	>= 200	80/20

ISSUE 2. AMORTIZATION OF COVID-19 DEFERRALS AND RATE SPREAD

Q. Which intervening Parties included discussion of issues related to the amortization or rate spread of deferral balances of PacifiCorp's COVID-19 costs in Opening Testimony?

A. Both CUB and SBUA discussed aspects of the COVID-19 deferrals, or the associated amortization(s) or rate spread amongst customer classes. AWEC, KWUA-OFBF, NIPPC, Vitesse, and Walmart did not discuss any aspect of COVID-19 deferrals, or the associated amortization(s) or rate spread in their respective Opening Testimonies, nor did PacifiCorp.

Q. What did CUB recommend?

A. CUB recommended delaying consideration of "PacifiCorp's deferral for COVID-19 until 2023 after the proposed rate effective date of UE 399."[37]

Q. What were CUB's reasons for this recommendation?

A. CUB stated two reasons. First was a concern for residential customer rate shock. The second reason was considering this issue in 2023 would allow all three years' (2020-2022) deferrals to be amortized simultaneously. CUB specifically recommended "delaying the amortization until the [COVID-19] deferral is closed, and results of operations for Pacific Power in 2022 are available."[38]

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[37] CUB/200, Gehrke/36.
[38] Id., page 37.

Q. Do you support CUB's recommendations?

A. No. I do not. Staff requested inclusion of the COVID-19 deferrals and the associated issues of amortization and rate spread.[39] Holding off amortization means a greater amount must be recovered later. An alternative to address any rate shock concern could be to revisit the length of amortization. Delaying amortization as CUB recommends distances those burdened with repayment from those that benefited from the terms of Commission Order No. 20-401 in Docket No. UM 2114.

Q. What did SBUA recommend in this proceeding?

A. SBUA's position is that "Schedule 23 rate class customers should only pay for costs, they imposed on the cost of serving this rate class."[40] SBUA argued that, as "[t]he focus in Oregon was on the residential customers and the costs incurred with the longer shutoff moratoria and other programs that applied primarily to the residential class. Therefore, those costs in Oregon should be paid only by the residential class as cost causer, they should pay the cost they imposed on the system."[41]

SBUA provided a primary recommendation and a contingent recommendation. The primary recommendation was that "COVID-19 cost recovery should not be considered in this general rate case where it was not included in the Company's filings and the costs are not completed.

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[39] See page 2 of the Corrected Staff Response to PacifiCorp Motion to Consolidated, filed March 30, 2022.
[40] Exhibit SBUA/100, Steele/21.
[41] Id., page 22.

The contingent recommendation was that "[i]f the Commission decides to consider COVID-19 cost recovery in this docket, then it should require the Company to notice customers and to provide testimony on its suggested recovery, and the Commission should apply cost causation principle in evaluating fair apportionment of costs."

Q. Do you support SBUA's recommendations?

A. No. I do not. Regarding SBUA's recommendation that "the Commission should apply cost causation principle in evaluating fair apportionment of [COVID-19 related] costs," I discussed this issue at some length in my Opening Testimony,[42] including support for the apportionment (rate spread) of some costs related to COVID-19 on a benefits-received basis.

Q. Does PacifiCorp discuss, in the Company's Reply Testimony, the recommendations of CUB, SBUA, or Staff regarding issues related to the amortization or rate spread of deferral balances of PacifiCorp's COVID-19 costs?

A. Yes. PacifiCorp discusses the amortization of COVID-19 deferral balances,[43, 44] but I could not locate discussion of Staff's proposed rate spread for the amortizations of COVID-19 deferrals in the Company's Reply Testimony.

Q. What salient points does PacifiCorp provide in Reply Testimony regarding amortization of the 2020 and 2021 COVID-19 deferrals?

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42 Exhibit Staff/1700, Storm/30-47.
43 Exhibit PAC/1200, Steward/5 and Steward/10-12.
44 Exhibit PAC/2000, Cheung/54-55.

A. I consider those points as follows:

- Staff's proposed amortization of 2020 and 2021 COVID-19 deferrals is not included in PacifiCorp's Reply Testimony revenue requirement.[45]
- PacifiCorp provides an estimated increase due to amortization of the 2020 and 2021 COVID-19 deferrals over four years of $4.7 million.[46]
- The Company is open to Staff's proposal.[47]
- PacifiCorp does not object to the basic proposal to begin amortizing the first two years of the deferral, but the Company "strongly disagrees" with Staff's proposed $376,593 disallowance.[48]
- The Company disagrees that there should be an earnings test set below [authorized] ROE, even though this does not impact amortization in this case.[49]
- The Company asserts that "the total deferred amounts Mr. Fox tabulated as eligible for deferral did not reflect any interest accumulation on the deferred amounts," contrary to Order No. 22-139 in Docket No. 2063.[50]

Q. What does PacifiCorp recommend regarding the amortization period?

A. The Company proposes to apply a four-year amortization period to the COVID-19 deferral instead of the three-year period proposed by Staff.

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45 Exhibit PAC/1200, Steward/5.
46 Id.
47 Id.
48 Exhibit PAC/1200, Steward/10-11. Staff discussed this issue in Opening Testimony at Staff/200, Fox/16 and Fox/18-21.
49 Exhibit PAC/1200, Steward/11.
50 Exhibit PAC/2000, Cheung/54-55.

Q. Why does PacifiCorp propose a four-year amortization period?

A. The Company sees this as a melding of CUB's proposal to delay amortization of the COVID-19 deferrals by one year with Staff's recommendation to begin amortization in 2023. This revision to Staff's recommended amortization period also reduces the annual rate impact on customers.[51]

Q. What is your reaction to PacifiCorp's proposed amortization period of four years?

A. I support it.

Q. What does Staff recommend regarding both Staff's proposed disallowance and the issue of interest on the deferral balances?

A. Staff discusses these matters in Exhibit Staff/1900.

Q. What do you recommend?

A. I recommend use of the rate spread recommendations in my Opening Testimony, as applied to the amortization amounts, with the allocation to specific schedules within a rate schedule on an equal cents per kWh basis.

I recommend use of a four-year amortization cycle, beginning with the rate-effective date of this proceeding.

I recommend the use of the $4.7 million annual amortization amount identified by PacifiCorp, after any adjustment recommended by Staff in Exhibit Staff/1900.

I recommend Staff increase the expense level by the impact of the amount derived in the prior recommendation, as PacifiCorp states it did not

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[51] Id. See also Table 17-9 at Exhibit Staff/1700, Storm/48.

include any amounts for amortization of COVID-19 deferrals in the Company's Reply Testimony.

ISSUE 3. PENSIONS AND POST-RETIREMENT MEDICAL

Q. Which intervening Parties included discussion of issues related to costs of PacifiCorp's pension or post-retirement medical plans in Opening Testimony?

A. No intervening Party discussed the costs of PacifiCorp's pension or post-retirement medical plans.

Q. What did PacifiCorp say in Reply Testimony on issues related to the Company's pension or post-retirement medical plan?

A. PacifiCorp provided an extended discussion of my Opening Testimony regarding the cost of these plans.[52] In essence, the Company disagrees with both my analyses and my recommendations on a variety of grounds. A common thread is that ASC 715-30 and 715-60 "require the use of explicit assumptions individually representing the best estimate of future activity associated with the plans' specific obligations."[53]

Q. Do you take issue with PacifiCorp's adherence to accounting standards regarding the calculation of net periodic benefit costs for its pension and post-retirement medical plans?

A. No. What I take issue with is the results selected by the Company to apply in calculating net periodic benefit costs. These "results" are the values of the discount rate and the Expected Return on Assets (EROA).

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[52] Exhibit PAC/1300, Kobliha/17-23.
[53] Exhibit PAC/1300, Kobliha/18-19.

Q. Please provide an example of this.

A. I use the history of PacifiCorp's EROA rate selected for its pension plan as an example. Historical values as well as that used for the Test Year are shown in Table 2500-4, which also includes the pension plan's actual returns.

Table 2500-4: Historical and Test Year EROA Values for PacifiCorp's Pension Plan[54]

	2019	2020	2021	2022	Test Year (2023)
EROA	7.0%	6.5%	6.0%	N/A	4.70%
Actual Return	20.2%	13.6%	11.0%	N/A	N/A
% Actual exceeds EROA	34.7%	47.8%	54.7%		

As can be seen, PacifiCorp has a near-term history of realizing actual returns on its portfolio that range on an annual basis from 34.7 percent (2019) to as much as 54.7 percent (2021) above the EROA rate.

Q. The U.S. stock market, as measured by the S&P 500 index, is down approximately 13.4 percent as of August 3, 2022. Will 2022 be a negative year for the S&P 500 or for the pension portfolio?

A. No one knows the answer to this question prior to year-end 2022. I note that the pension plan portfolio is highly likely to have less—and perhaps considerably less—than 100 percent invested in stock investments, which presumably results in a portfolio with less volatility and less variation in returns

54 Values for EROA and Actual Return taken from PacifiCorp's response to Standard Data Request 59. Values for % Actual over EROA are calculated by Staff using information provided by PacifiCorp in response to SDR 59.

year-to-year. I do know that actual returns exceeding expected returns by approximately 46 percent[55] allows for the occasional down year.

Q. What do you now recommend?

A. I recommend the Commission reduce PacifiCorp's pension plan expense in rates by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, which is the impact I calculate based on information included in PacifiCorp's response to Standard Data Request 59 and confidential response to Standard Data Request 60. This amount is derived using the EROA value of 6.0 percent that I now recommend, which is less than the 6.7 percent I recommended in my Opening Testimony. Additionally, it matches the EROA value PacifiCorp used in 2021, as shown in Table 2500-4.

To provide additional context for the recommended 6.0 percent EROA and regarding a hypothetical decline in portfolio value in 2022, a portfolio growing at the historical rates of return PacifiCorp's pension has over the 2019-2021 period could decline by as much as 20.7 percent in 2022 and still have an average growth rate of 6.0 percent over the 2019-2022 period.[56]

I also recommend against the Commission accepting the updates "based on the latest projections performed by the Company's actuaries," as proposed by PacifiCorp.[57]

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[55] This value is the average percent by which PacifiCorp's pension plan actual returns exceeded the expected returns (EROA values) over the period 2019-2021.

[56] I use, in this context, the arithmetic mean construction of 2019-2022 growth rates, which does not require that I make any particular assumption regarding withdrawal amounts as they have no impact.

[57] Exhibit PAC/1300, Kobliha/17 and Kobliha/23.

Q. Why do you recommend against the use of PacifiCorp's actuaries' "latest projections?"

A. My concern is regarding an implied optionality that could exist with usage of the recommended updates. While acknowledging that such updates are unlikely to be without cost, PacifiCorp hypothetically could request updates based on the level of interest rates at different points of time after filing of the Company's Direct Testimony and before filing Surrebuttal Testimony and select the update most favorable to shareholders.

If Staff implements a rule that an update for pension purposes should always be used if available, it presumably allows PacifiCorp to choose whether an update applies or not as dictated by when it is received relative to filing dates of the Company's testimony in a general rate case proceeding.

Q. What is the expense implication of this recommendation?

A. PacifiCorp states in testimony that the update results in a $1.6 million increase, on an Oregon-allocated basis, inclusive of an update to the projected 2022 settlement loss to $11.9 million from the $9.8 million projected in the Company's Direct Testimony. Accordingly, I recommend the Commission reduce PacifiCorp's allowed expense recovery in UE 399 by $1.6 million.

ISSUE 4. MULTI-STATE PROCESS

Q. You stated in Opening Testimony your review of PacifiCorp's use of allocation factors was incomplete and that you issued data requests to the Company regarding these. Have the responses allowed you to complete your review?

A. Yes.

Q. Do you have any recommendations as a result of your review?

A. No.

Q. Which intervening Parties included discussion of issues related to PacifiCorp's Multi-State Process?

A. AWEC discussed two issues regarding how interjurisdictional allocation factors had been calculated. The first issue was regarding loads associated with Utah Schedule 34.[58] The second issue was regarding the Utah Demand-side Management DSM allocation.[59]

Q. Do you discuss these issues in your testimony?

A. No. These issues are discussed in Exhibits Staff/2100 and Staff/2400.

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[58] Exhibit AWEC/100, Mullins/24-25.
[59] Id., pages 25-26.

ISSUE 5. KLAMATH HYDROELECTRIC SETTLEMENT AGREEMENT AND KRRC

Q. You had not resolved in Opening Testimony how the $33 million system value coded to FERC 545 was developed.[60] Have PacifiCorp's responses to your data requests addressed this question?

A. Yes. PacifiCorp's response to my data request 538 included the following:

> The $33 million adjustment represents the removal reversal of the recording of an accrual for costs associated with meeting the Company's obligations under the Klamath Hydroelectric Settlement Agreement (KHSA), specifically for future hatchery production obligations and land transfer and associated environmental remediation of properties that will be transferred with the Lower Klamath Project hydroelectric facilities (Iron Gate, Copco No. 1, Copco No. 2 and J.C. Boyle). Recovery of these costs may be sought in a future proceeding once actual costs have been incurred.

Q. Did PacifiCorp remove Oregon's $8.6 million share of this expense from the Base Year as a normalizing adjustment?

A. Yes.[61] As a result, these estimated expenses play no role in PacifiCorp's proposed Test Year revenue requirement in this proceeding.

Q. Which intervening Parties included discussion of issues related to the KHSA or KRRC?

A. None of them.

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[60] Exhibit Staff/1700, Storm/8-9.
[61] Exhibit PAC/1000, Cheung/19.

ISSUE 6, ENERGY VISION 2020 PROJECTS

Q. Which intervening Parties included discussion of issues related to Energy Vison 2020 projects in opening testimony?

A. AWEC discussed an issue involving the delayed in-service date for the TB Flats wind facility.[62]

Q. Do you discuss the TB Flats wind facility in your testimony?

A. No. Any discussion of this facility by Staff in Rebuttal Testimony appears in one or both of Exhibits Staff/1900 or Staff/2000.

Q. Does this conclude your testimony?

A. Yes.

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62 Exhibit AWEC/100, Mullins/22-23.

CASE: UE 399
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2600

Rebuttal Testimony

August 11, 2022

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

A. My name is Brian Fjeldheim. I am a Senior Financial Analyst employed in the Rates, Finance, and Audit 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 previous testimony and supporting exhibits in this case were provided in Staff/1100-02, Fjeldheim.

Q. What is the purpose of your Rebuttal Testimony?

A. I present Staff's analysis and rebuttal to Pacific Power's (PacifiCorp or Company) Reply Testimony filed July 19, 2022, regarding Staff's adjustments to customer accounts expense (non-labor) of $3.285 million; a revenue sensitive uncollectible accounts factor of 0.336 percent, resulting in a reduction of $2.046 million; and removal of legal expenses and fees totaling $2.9 million from rate base. To Staff's knowledge, no other Parties in this case addressed the issues above.

Q. Did you prepare any exhibits for this Rebuttal Testimony?

A. Yes. I prepared the following exhibit: Exhibit Staff/2601 – Response to Staff Data Requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Customer Accounts Expenses (Non-Labor)....................................... 2
Issue 2. Uncollectible Accounts.. 6
Issue 3. Legal Expenses and Fees... 10

ISSUE 1. CUSTOMER ACCOUNTS EXPENSES (NON-LABOR)

Q. Please summarize Staff's opening testimony position on this issue.

A. Staff's position in opening testimony is the Company's accounting data, filed in response to Staff's Standard Data Requests (SDRs) 057 and 058(b), contained unexplained discrepancies in non-labor dollar amounts for numerous operations and maintenance (O&M) FERC accounts.[1] Specifically, non-labor accounting data for many FERC accounts supplied in PacifiCorp's responses to SDRs 057 and 058(b)[2] for the Company's Base Year (July 1, 2020, to June 30, 2021) did not reconcile with one another.

Q. Please summarize Staff's analysis of customer accounts expenses in Opening Testimony.

A. Because the base year accounting data for several O&M FERC accounts were materially different between PacifiCorp's responses to SDR 057 and 058(b), Staff was unable to rely upon the accuracy of the 2019 and 2020 historical expenditure data included in the Company's SDR 058(b) response. Due to the increased level of accounting detail required in SDR 057, Staff treated this data as the "book of record" when comparing and analyzing the differences in base year accounting data between SDR 057 and 058(b).

By individual FERC account, Staff calculated a ratio of the difference between SDR 057 and 058(b) base year expenditures and then applied this

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1 Staff/1100, Fjeldheim/9-12.

2 SDR 057 requests detailed accounting data for the full base year period and should exclude all labor expenses. SDR 058(b) requests, by FERC account, summary accounting data for the base year, the two preceding calendar years, and the utility's projected Test Year need. Both SDRs require the exclusion of labor expenses.

ratio to the historical summary data for 2019 and 2020 included in SDR 058(b). Staff then escalated the adjusted 2019 and 2020 expenditures, by individual FERC account, to Base Year equivalent dollar amounts using the All-Urban Consumer Price Index (CPI-U)[3] for 2019, 2020, and the first half of 2021 for the respective years. Staff then calculated a three-year average of the escalated 2019, 2020, and Base Year expenditures.

Lastly, Staff escalated the three-year average to the Test Year period using the 2022 and 2023 CPI-U factors and compared this result against the Company's Test Year dollar amounts for each FERC account amount provided in SDR 058(b). The dollar differences between Staff's calculated amounts for FERC accounts 901-903 and 905, and PacifiCorp's response to SDR 058(b) resulted in Staff's proposed Opening Testimony reduction of $3.285 million in the Test Year.[4]

Q. Please summarize PacifiCorp's position on this issue.

A. In PacifiCorp's Reply Testimony, Ms. Cheung noted:

> [A] discrepancy was discovered in the data provided in SDR 057 for FERC account 903. While the Company has made a good faith effort to provide all of the non-labor accounting data for the Base Period in SDR 057, some accounts for contractor labor were mistakenly left out of the response. One account in particular in the FERC account 903 base period expense totaled $3.4 million on an Oregon allocated basis, explaining the large difference that Mr. Fjeldheim noted. The Company is preparing a revised response to SDR 057 to include these missing accounts and will submit it shortly.[5]

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[3] Staff used the June 2022 CPI–U provided by the Oregon Office of Economic Analysis (OEA).
[4] Staff Excel files "SDR 057 vs 058(b), 1st Supp," "OPUC 058-2 1st SUPP Attach (BF notes)," and "UE 399 Staff Exhibit 1100 Issue 1 TD O&M v3 Fjeldheim 6.8.22."
[5] See PAC/2000, Cheung/35 at 10-19.

Q. Has Staff's position on this issue changed?

A. No. The Company claims the dollar difference between SDRs 057 and 058(b) results from an error in the Company's accounting data provided in response to SDR 057 that excluded a component of contract labor in FERC account 903—Customer records and collection expenses—to the tune of approximately $3.4 million.[6] However, the Company did not produce any new evidence to support this claim in PacifiCorp's Reply Testimony filed July 19, 2022.

On the afternoon of August 4, 2022, the Company furnished Staff and Parties with a revised response to SDR 057, comprised of 18 separate Excel files containing Base Year accounting details for FERC accounts 502–935. Based on Staff's experience organizing and investigating the Company's original SDR 057 response, significant time and effort is needed to investigate the Company's revised submission.

Due to the late date in the procedural schedule, Staff's imminent need to file Rebuttal Testimony, and the Company's lack of timely providing Parties with evidence to support the filed case or even its Reply Testimony position, Staff continues to recommend a reduction of $3.285 million to Test Year customer accounts expenses. Despite the Company providing additional supporting documents, the $3.285 million could be thought of as a management disallowance for not providing information in a general rate case on a timely basis. In providing this information four business days prior to the filing deadline for Rebuttal Testimony, PacifiCorp foreclosed Staff and Parties

6 See PAC/2000, Cheung/35 at 10-19.

ability to perform in-depth analysis for inclusion in Rebuttal Testimony. Staff and Parties must be allowed sufficient time to review information provided by the Company.

Q. What does Staff recommend?

A. Staff recommends a reduction of $3.285 million to Test Year non-labor customer accounts expenses.

ISSUE 2. UNCOLLECTIBLE ACCOUNTS

Q. Please summarize Staff's position on this issue.

A. COVID-19 represents a once in a century pandemic event, with significant global social and economic disruptions beginning at the outset of 2020 and continuing through much of 2021. On this basis, Staff recommended the Company utilize the uncollectible account rate of 0.336 percent established in the Company's prior rate case filing in Docket No. UG 374. The previous uncollectible rate predates the onset of COVID-19 and effectively ignores the ensuing economic turmoil that occurred throughout the Base Year period and is unlikely to exist in the Test Year. Staff's proposed adjustment down from the Company's filed uncollectible rate of 0.500 percent results in a Test Year reduction of $2.046 million, based on the Company's filed rate case.

Q. Does PacifiCorp agree with Staff's position on this issue?

A. No. Ms. Cheung states in her Reply Testimony:

> Uncollectible rates are unique to each individual utility based on a myriad of circumstances. While it may be reasonable for NW Natural to use its uncollectible factor from its prior general rate case as a proxy for calculating uncollectible expense absent COVID-19 impacts, the same is not true for PacifiCorp. The Company analyzed uncollectible expenses deferred in the base period and based on uncollectible expenses and general business revenues as filed in the Company's direct filing, if these COVID-19 related amounts were normalized out of test year uncollectible expense, the Company's uncollectible rate in this case would only decrease slightly from 0.500 percent to 0.455 percent.[7]

[7] See PAC/2000, Cheung/28 at 1-12.

Table 4 of Ms. Cheung's testimony provided the Company's approved uncollectible rates from the Company's three prior rate cases preceding Docket No. UE 374.[8]

- Docket UE 217 (2011 GRC) Uncollectible rate = 0.618 percent.
- Docket UE 246 (2013 GRC) Uncollectible rate = 0.493 percent.
- Docket UE 263 (2014 GRC) Uncollectible rate = 0.525 percent.

Q. Does Staff agree with the Company's position that the uncollectible rate of 0.336 percent approved in Docket No. UE 374 is anomalously low?

A. No. Staff noted the time periods of the prior rate case filings referenced in Table 4 of Ms. Cheung's testimony in Docket Nos. UE 217, UE 246, and UE 263 occurred during, and shortly after, the economic time period colloquially referred to in the United States as the "Great Recession," whereas the rate case filing in Docket No. UE 374 occurred during a period of relative economic strength and prosperity. Based on the June 2022 Oregon economic outlook publish by Oregon's Office of Economic Analysis (OEA), the U.S. at large, and Oregon specifically, have generally completed the economic rebound from the COVID-19 sparked recession of 2020 and 2021. In particular, the OEA noted Oregon's unemployment rate of 3.6 percent is near historic lows, the relative strength of the state's economy, and significant wage growth amongst the lowest paid 20 percent of workers.[9]

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[8] See PAC/2000, Cheung/28 at 13, TABLE 4 – PacifiCorp Approved Uncollectible Rates.

[9] Oregon Office of Economic Analysis (June 2022). *Oregon Economic and Revenue Forecast,* pgs. 2-16. https://www.oregon.gov/das/OEA/Documents/forecast0622.pdf.

Oregon's current economic indicators are reminiscent of the state's economy during PacifiCorp's previous rate case filing in Docket No. UE 374. As such, the uncollectible rate of 0.366 percent established in the prior rate case is likely a better barometer of the current and near-term economic environment affecting the Company's customers ability to pay their utility bills timely.

Q. Has Staff's position on this issue changed?

A. No. The Company did not provide compelling evidence that the proposed uncollectible rate of 0.500 percent is reasonable or just. The Company dismissed the previous uncollectible rate approved in Docket No. UE 374 as "anomalous" and should not be used as a reasonable proxy to eliminate the unprecedented and transitory economic impacts from COVID-19, and instead chose to reference uncollectible rates from 8-11 years ago. The Company's position also ignores the significant COVID–19 arrearage deferrals approved by the Commission[10] as well as Federal COVID–19 utility aid programs.[11]

Staff continues to see significant economic similarities between the prior rate case period and the current filing, and Staff recommends the continued

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[10] See UE 399 Staff/200, Fox/2 at 14-18. Staff proposed amortization of $17.010 million of the Company's COVID-19 deferral, approved by Order No. 22-139 in Docket No. UM 2063.

[11] The U.S. government, as part of the Emergency Rental Assistance Program, provided $21.6 billion to states, territories, and local governments to help households unable to pay rent or utilities during COVID-19. See https://home.treasury.gov/policy-issues/coronavirus/assistance-for-state-local-and-tribal-governments#:~:text=The%20American%20Rescue%20Plan%20provides%20%2421.6%20billion%20for%20states%2C%20territories,to%20the%20COVID%2D19%20crisis.

use of the uncollectible rate approved in the Company's prior general rate case in Docket No. UE 374.[12]

Q. What does Staff recommend?

A. Staff recommends the uncollectible rate of 0.366 percent remain unchanged, resulting in a $2.046 million reduction to Test Year expense.

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[12] In Docket No. UE 374 Staff and PacifiCorp used the uncollectible rate of 0.336 percent in the final revenue requirement model (Staff) and the Jurisdictional Allocation (JAM) model (PacifiCorp).

ISSUE 3. LEGAL EXPENSES AND FEES

Q. Please summarize Staff's position on this issue.

A. Based on the Company's original response to Staff DR 349, there were 440 accounting entries Staff identified for legal expenses and fees with negative dollar amounts that lacked specific supporting transaction details. Staff believed these negative accounting entries represented capitalization adjustments for legal fees expenses. On this basis, Staff recommended a reduction of $2.9 million thereby removing the associated dollar amounts of the 440 accounting entries out of Test Year rate base.

Q. Please summarize the Company's position on this issue.

A. In the Company's Reply Testimony, Ms. Cheung stated:

> While the specific negative entries in question do not show any descriptions in the "Text" field, as often these types of system generated settlement entries do not, there is a corresponding debit entry for the same transaction that most often will reflect a description of the order, or cost object that the amounts are being moved to. I have prepared a confidential workpaper "Attach OPUC 349 – Legal Expense Support CONF.xlsx" that will be submitted in conjunction with my reply testimony. In the tab labelled "OPUC 349 CONF", the Company has provided the complete listing of offsetting debit entries corresponding to the 440 lines of credit amounts.[13]

Q. Does Staff find the Company's position reasonable?

A. While the Company's revised supporting workpaper "Attach OPUC 349 – Legal Expense Support CONF.xlsx" largely addresses Staff's concern regarding the lack of accounting entry detail for the types of transaction entries for legal expenses and fees noted in Staff/1100, Fjeldheim/37-38, Staff notes that the

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[13] See PAC/2000, Cheung/38 at 16-23.

Company materially failed to fully address Staff's request for additional accounting data in Staff DR 349. First, in the Company's original response to Staff DR 349, PacifiCorp failed to follow Staff's instruction that dollar amounts be provided on both a Company wide basis and an Oregon allocated basis. The Company apparently only provided dollar amounts on a Company wide basis and omitted an Oregon allocated dollar amount for each line item. Second, the Company failed to provide the requested accounting data for the correct Base Year period. Per Ms. Cheung:

> In reviewing Mr. Fjeldheim's analysis of OPUC data request 349, however, the Company noticed that the response and attachment provided reflected data for the 12 months ended June 2020, which is the incorrect base period. The Company apologizes for the error and has immediately prepared a revised response to OPUC data request 349 that was submitted on July 15, 2022, to provide the corresponding data requested for the 12 months ended June 2021.[14]

Unfortunately, PacifiCorp did not remedy this error with the revised Confidential response to Staff DR 349. While the Company provided additional accounting details, including a breakout for Oregon allocated and system wide legal expenditures, PacifiCorp's Excel file "OPUC 349 1st REVISED CONF", Excel Tab "Attach OPUC 349 1stRevised CONF" did not provide accounting data for the Company's filed Base Year.[15] Instead, the Company provided accounting data for July 1, 2021, to June 30, 2022.

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[14] See PAC/2000, Cheung/39 at 14-19.
[15] The Base Year period in the Company's filing is July 1, 2020 – June 30, 2021.

Staff remains concerned that fundamental errors and/or omissions occurred in several iterations of the Company's accounting data submissions throughout the current rate case filing. Historical expenditure data drives a significant portion of Staff's and Parties prudence analysis. Accounting data accuracy was also a significant Staff concern in PacifiCorp's prior rate case. In both the current and prior rate case filings, Staff and the Company had to invest significant time, effort, and limited resources to correct and refine the Company's accounting data. While Staff appreciates the effort by the Company to develop and refine the process by which accounting data is generated and submitted in a general rate case filing, more needs to be done to improve the timely filing of accurate and reliable accounting data necessary to meet the Commission's rate case filing requirements.

Q. Does Staff propose an adjustment for legal expenses and fees?

A. Yes. Because the Company has not provided accounting data for the correct Base Year period, there is no means for Staff or Parties to determine whether the Company's Reply Testimony is correct concerning the 440 transactions identified in Staff's Opening Testimony. Due to the late date in the procedural schedule and PacifiCorp's lack of timely providing Staff with the requested accounting data for the correct Base Year period, Staff continues to recommend a reduction of $2.9 million to Test Year plant. Similar to Issue 1 of my Rebuttal Testimony, this adjustment can be thought of as a management disallowance for not providing correct information in a general rate case on a timely basis.

Staff also recommends the Commission direct PacifiCorp to engage in a series of workshops with Staff and Parties to develop a binding, workable solution(s) for submission of accurate and sufficiently detailed accounting data necessary to meet the requirements of Staff SDRs 057 and 058 prior to the Company's next general rate case filing.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 399
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2601

PacifiCorp Responses to Staff Data Requests

Exhibits in Support
Of Rebuttal Testimony

August 11, 2022

Docket No: UE 399

UE 399 / PacifiCorp
August 08 , 2022
OPUC Data Request 602

OPUC Data Request 602

Accounting Data - Please provide a copy of PacifiCorp's slide presentation from the July 27 meeting with Staff and Parties pertaining to the Company's responses to Standard Data Requests (SDRs) 057 and 058.

Response to OPUC Data Request 602

Please refer to Attachment OPUC 602.

Oregon 2023 General Rate Case
Labor v. Non-Labor Overview
(SDR 057 & 058)

July 27, 2022





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SDR 057 – Non-Labor Transaction Level Details

- SDR 057 presents a straight general ledger (GL) view
- Manual process to compile
  - Labor v. Non-labor reporting is not a built-in function in SAP
  - Both primary and secondary labor GLs are manually identified to be excluded from SDR 057 data set
    - Primary Accounts: Wages & Salaries, Benefits GL etc.
    - Secondary Accounts: Sub-ledger accounts used to charge time to projects to keep track of what work has been done at a finer level of detail. These cross charges are made using fully-loaded activity rates that incorporates salary, benefits, and other department overhead.
      - This cross-charge methodology ensures costs are assigned to the right “place” – be it work orders, functions, capital projects or jurisdictional location.
      - Secondary labor vs. Primary labor expense mapping can be done on a single-employee basis. But in a system of over 4,600 employees, this reconciliation does not exist.
  - Ex. SDR 057_FERC 902 SAMPLE
- One customer account (secondary GL) is missing from the non-labor expenses submitted SDR 057 response
  - i.e. secondary account is being pulled out (and balances excluded as a labor account, when it’s actually not)
  - SDR 057 non-labor expenses are artificially low
- An update is being prepared to correct for this oversight

SDR 058-2 – Historical FERC balances (excl. Labor)

- SDR 058 presents a FERC view
- SDR 058-2 takes total FERC account balance, and isolates Labor components utilizing the Company's Wages & Employee Benefits Adjustment (WEBA) and Pension Non-Service Expense Adjustment
  - In the last GRC (UE 374), SDR 058 was prepared utilizing the GL basis of identifying labor expenses as described in the SDR 057 slide, which resulted in the non-labor totals between SDR 058 and SDR 057 matching for all historical years
    - However, Test Year labor expenses are not prepared on this GL basis.
    - In UE 374, SDR 058-2 Test Year amounts could not be compared to the non-labor costs reported for the other historical years.
    - In order to provide better comparability to historical expense levels, we switched to prepare SDR 058-2 utilizing a FERC account view in the current proceeding.
- WEBA is derived based on primary labor expense accounts
  - In the rate case, these labor expenses are escalated using labor escalators, and then spread across FERC accounts using FERC Form 1's approximated labor split
  - Ex. Simplified WEBA example
  - Because of the FERC spread methodology utilized in the preparation of SDR 058-2, the non-labor expense calculated based on this view will not match exactly to the GL view information presented in SDR 057

Labor vs. Non-Labor Escalation

- Labor expenses are escalated through WEBA, and Pension Non-Service Expense Adjustment
- The remaining balance (i.e. non-labor expenses) are then escalated by IHS escalation indices in the Company's O&M Escalation Adjustment
- Ex. O&M Expense Escalation Template
- This is important, because a potential reduction in the Labor category of expenses could just mean that the expense is removed from the subset of labor expenses, but included in non-labor expenses for Test Period escalation

Key Take-aways

- Non-labor expenses identified in SDR 057 will not exactly match with SDR 058-2
- For recommended reductions based on a "category" dispute (i.e. labor vs. non-labor), identified expenses should not be removed in its entirety from Test Year results.
  - Instead, an adjustment to reflect the exclusion of the disputed expense from labor expenses, which then gets added to non-labor expense for escalation would be more appropriate.


Questions?

CASE: UE 399
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2700

Rebuttal Testimony

August 11, 2022

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

A. My name is Julie Jent. I am a Senior Utility Analyst employed in the Rates, Finance and Audit 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, see Staff Exhibit 1200-1204.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide Staff's review of parties' direct testimony, if any, as well as PacifiCorp's reply testimony regarding advertising and various types of Insurance.

Q. Did you prepare an exhibit for this surrebuttal testimony?

A. Yes. I prepared Exhibit Staff/2701, consisting of 14 pages.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Advertising 2
Issue 2. Current Medical and Health Insurance 6
Issue 3. Insurance and Risk 8

ISSUE 1. ADVERTISING

Q. What was Staff's recommendation as stated in their opening testimony?

A. Staff proposed the removal of Category C advertising expenses and the removal of unclassified advertising expenses, which resulted in an adjustment of $111,483 to the Test Year Oregon allocated amount of $1,692,735.[1]

Q. Did other intervenors comment on advertising in their opening testimonies?

A. Yes. Small Business Utility Advocates (SBUA) reiterated the agreement of the stipulating parties with PacifiCorp in UE 374, to review its marketing, outreach, and education with respect to Schedule 23 customers and includes no adjustment to the revenue requirement.[2] However, its recommendation is that "The Commission should direct the Company to produce a Marketing, Education, and Outreach Plan specific to small general service customers."[3]

Q. What is Staff's view of SBUA's recommendation?

A. Staff recognizes that the SBUA request is made by a representative of the small-business customer class and appears to be a reasonable request.[4]

Q. Can you please restate Staff's adjustment and supporting arguments for excluding Category C advertising.

A. Staff recommended removing Category C expenses, which totaled $67,178 for the test year (TY). OAR 860-026-0022 sets out how advertising expenses

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1 Staff/1200 Jent/12
2 SBUA/100 Steele/17
3 SBUA/100 Steele/24
4 *See* Staff's response to SBUA DR No. 22, which was completed by Curtis Dlouhy.

should be addressed in a rate case. Category C advertising can be included in rates, but the utility carries the burden of showing that any advertising expenses in this category are just and reasonable. "The primary purpose of [these expenses] is not to convey information, but to enhance the credibility, reputation, character, or image of an entity or institution…"[5] However, PacifiCorp has failed to provide justification for why these costs are just, reasonable, and should be included in rates. The Company's response to SDR 104, as well as subsequent DRs 360-362, contained inadequate details and information to support the Company's assertion that these expenses are just and reasonable.[6]

Additionally, Staff has found that the Category C expenses are primarily related to job recruitment advertising expenses and historic windstorm media relations from the fall of 2020, which do not fulfill, in Staff's view, the burden of proof required for inclusion into rates. In addition, these costs seem overestimated, given that in the previous rate case, Category C advertising costs were 20 percent of what they are in UE 399.[7] Lastly, with regards to Staff's assumption that some Blue-Sky Program costs are included in Category C advertising, Staff found that the Blue-Sky line-item shown in Table 6 of the Company's rebuttal is listed as $1,683. Yet, the adjustment, which PAC stated

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5 OAR 860-026-0022 (1) (c).
6 *See* Staff/2701 PAC Response to DR 361(pdf) and 362 (pdf).
7 *See* Staff/2701 PAC Response to DR 181 (pdf), DR 181 Attach (electronic spreadsheet), and Staff/2702 PAC CONF Response to DR 586 (pdf).

removed these costs, was only $1,540.[8] Staff is still concerned that Blue-Sky Program costs are included in the Company's Category C expenses.

Q. What was PAC's rebuttal to the removal of Category C advertising expenses?

A. The Company rejects Staff's recommendation and reiterated that the Blue-Sky program is a self-sustained voluntary program that does not impact the revenue requirement.[9]

Q. Does Staff have an update to their recommendation with regards to Category C Advertising?

A. No. Staff continues to recommend that Category C advertising should be removed. The Company did not provide sufficient justification for why Category C should be included in rates.

Q. Please restate Staff's opening testimony adjustment and supporting arguments for excluding unclassified advertising.

A. Staff recommended removing $44,305 in unclassified advertising expenses.

Q. What was PAC's rebuttal to the removal of unclassified advertising expenses?

A. PacifiCorp accepted a partial amount of Staff's adjustment, $23,717.[10] PAC verified that $1,619 should be reclassified as Category A, $3,048 should be

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[8] 4.1 Miscellaneous Expense & Revenues Adjustment

[9] PAC/2000 Cheung/8.

[10] Escalation is reflected through Adjustment 4.10, O&M Escalation Adjustment. Based on the above discovery, the Company has prepared a revised response to OPUC data request 176 to provide the latest information. This revised data response was submitted on July 15, 2022. *See* Staff/2701 OPUC 176-1 1st revised (electronic spreadsheet).

reclassified as Category B, and $133 should be reclassified as Category C. In addition, they claimed that $14,191 of wildfire safety for other states were already removed through the Company's Adjustment 4.1 and that $1,596 are labor-related expenses and are normalized to properly reflect Test Year levels through Wages & Employees Benefits Adjustment – therefore captured in another adjustment.[11]

Q. Does Staff have an update to their recommendation with regards to unclassified Advertising Expenses?

A. Yes. Staff accepts the reclassification of unclassified expenses and so the remaining adjustment equals $23,717.[12]

Q. Given this discussion, is Staff revising its recommendations from its direct testimony?

A. Staff recommends an adjustment totaling $91,028. This reflects the sum of $67,311 in updated Category C advertising expenses and $23,717 in unclassified advertising expenses.

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[11] PAC/2002 Cheung/191 Page R_8.

[12] $23,717 = $44,305 (OT Recommendation) – ($1,609 (Reclassified Category A) + $3,408 (Reclassified Category B) + $133 (Reclassified Category C) + $14,191 (Wildfire Safety that is Already Adjusted out) + $1,596 (Labor Related Expenses Captured in Another Adjustment)).

ISSUE 2. CURRENT MEDICAL AND HEALTH INSURANCE

Q. What was Staff's recommendation as stated in their Opening Testimony?

A. Staff recommended bringing dental and vision benefits in line with national health inflation trends, thereby removing **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[13]

Q. Have you had a chance to update your adjustment since the issuance of your opening testimony?

A. Yes. As explained in this testimony, Staff no longer sponsors an adjustment in this area. Staff performed updated calculations using the Urban-CPI rather than the Information Handling Services (IHS) Markit escalation index for FERC account 926 (Employee Pension & Benefits), which showed that overall current medical requests were appropriate, and in fact lower than the all Urban-CPI projections. In addition, Staff read through supporting DR responses, which detailed actuarial projections.[14]

Q. How does the Company respond to Staff's proposed revisions to dental and vision expense?

A. PacifiCorp did not agree with the reduction of the test year dental and vision expense. They informed Staff that the switch to an escalation model using IHS escalators is inconsistent with PacifiCorp's dental and vision plans, that are self-insured. **[BEGIN CONFIDENTIAL]** [redacted]

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[13] Staff/1200 Jent/19.

[14] *See* Staff/2702 PAC CONF Response to DR 578 (pdf) and CONF Attachments 578-1 (pdf) and 578-2 (electronic spreadsheet).

[redacted] **[END CONFIDENTIAL]**[15]

Q. Given the discussion above, is Staff revising its recommendations from its direct testimony on Current Medical and Health Insurance?

A. Yes. As stated above, Staff no longer sponsors an adjustment to the Test Year amounts for current medical and health insurance proposed by the Company.

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15 PAC/2000 Cheung/16.

ISSUE 3. INSURANCE AND RISK

Q. What was Staff's recommendation as stated in their Opening Testimony?

A. Staff recommended an adjustment to the Oregon-Allocated of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[16] This included:

1. Increasing insured loss coverage given large amounts of uninsured losses;
2. Removing $2,093,761 million for a 10-year amortization; and
3. [**BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. How did PacifiCorp respond to the concern that the Company should increase the insured loss coverage with an outside provider?

A. They stated that transmission and distribution property insurance does not exist.[17]

Q. Does Staff update their first recommendation based on PAC's analysis?

A. Yes. Staff acknowledges that the Company's coverage with Berkshire Hathaway Energy Company expired in March 2011 and since then, PAC has relied on a self-insurance reserve. Their method of self-insurance was approved in docket UE 217, in which monthly property accrual amounts are based on a 10-year average of actual property losses each year, then

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[16] Staff/1200 Jent/28.
[17] PAC/2000 Cheung/21.

escalated by the Urban CPI. Therefore, Staff removes its initial recommendation to increase coverage.

Q. How did the Company respond to the concern related to the property reserve balance, which was in a debit position of $20.9 million?

A. PacifiCorp informed Staff that the $20.9 million debit balance represents actual property damage amounts that were spent over and above the amounts that were approved to be accrued into the property reserve rather than being estimates.[18] They also offered two alternatives, to either amortize over a period other than ten years or change how their monthly accrual average is calculated to shorten the number of years being averaged to increase the level of on-going accruals.

Q. Does Staff update their recommendation to remove their property reserve amortization based on PAC's analysis?

A. Yes. Staff agrees with PacifiCorp's assessment of their excess property costs and the decision to not file a deferral in this instance. PAC seeks to amortize this amount to lower the balance that Oregon customers owe for property insurance expenses that were not covered by the level of accrual in rates over the past decade. However, PacifiCorp states that the property reserve balance has grown from $20.9 million in June 2021 to $26.1 million in June 2022.[19] While Staff does not believe PacifiCorp is seeking recovery of this additional

[18] PAC/2000 Cheung/22.
[19] PAC/2000 Cheung/24.

increase, we want to state that Staff does not support including this additional increase in this GRC.

Q. How did PAC respond to the concerns of including a low claims bonus?

A. PacifiCorp informed Staff that the Company is already reflecting **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Does Staff update its recommendation with regards to bonuses?

A. Yes. Staff discovered that this amount was already excluded from the TY through PacifiCorp reply testimony and in PacifiCorp's Confidential Response to DR 583 that provides the underlying data for the bonus amount.[20]

Q. Has the Company made any additional updates to Adjustment 4.5, Insurance Expense?

A. Yes. As a result of updated allocation factors, accrual reserves have changed slightly from the amounts included in Staff's direct testimony. The net impact of the update is a reduction of about $4 thousand in revenue requirement."[21]

Q. Did any intervenors comment on Insurance?

A. Yes. The Alliance of Western Energy Consumers (AWEC) recommended to remove **[BEGIN CONFIDENTIAL]** [redacted]

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20 *See* Staff/2702 PAC Response to DR 583 (pdf) and DR 583 Attach (electronic spreadsheet).
21 PAC/2000 Cheung/20.

[redacted] **[END CONFIDENTIAL]**.[22]

Q. How did the Company respond to these concerns?

A. PacifiCorp initially noted that the increase to liability insurance on an Oregon allocated basis of $5,649,850 is attributable to wildfire risk and other factors outside of PacifiCorp's control.[23] In PacifiCorp's reply testimony, the Company referred back to the testimony of Shelley E. McCoy in UE 374, where they describe that the policies cover claims in any state (including California) and are allocated to all states as the policies cover system-allocated assets. In addition, these premiums were approved for inclusion in Order 20-473. At that time, the Commission acknowledged the Company's explanation of premium increases being driven by California wildfire exposure and stated, "We note the cost of the Delta Fire damaged facilities is also system-allocated, illustrating the impact of California wildfire risk on Oregon customers. We find that PacifiCorp has demonstrated that its proposed level of expense for insurance is reasonable...."[24]

Q. What is Staff's response to AWECs adjustment and the Company's reply testimony?

A. Staff reviewed SDR No. 69 and Confidential DR No. 16 which showed the amounts attributed to California wildfire premiums were the main source of the

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22 AWEC/100 Mullins/13 and AWEC/102 CONF.
23 PAC/1000 Cheung/21 11-12.
24 Order No. 20-473 at 108.

increase in liability insurance and agrees with AWEC's assessment that this portion should be excluded.[25] Total liability premiums in Oregon increased **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[26] Staff agrees with AWEC that these premiums should be removed. In addition, according to the Spring 2022 update from Market Realities, liabilities increases are expected to increase from a range of +5 percent to +12.5 percent.[27]

Q. What additional support does Staff have for removing these costs from this GRC?

A. Staff does not read the language in Order No. 20-473 to mean that the Commission supports allocating insurance premiums related to wildfire risk in all states going forward. Instead, Staff believes that the Company bears the same burden in this case as it did in UE 374 to demonstrate that the California wildfire risk impacts Oregon customers, and therefore should be allocated system-wide in this case. In that Order, the Commission noted that the cost of the Delta Fire damaged facilities were also system-allocated, which illustrated the impact of California wildfire risk for Oregon customers.[28] The Company

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[25] Staff/2702 PAC CONF Response to SDR 69-1 (electronic spreadsheet), SDR 69-2 (pdf) and PAC CONF Response to DR 16 from AWEC (electronic spreadsheet).

[26] *Ibid*.

[27] IMR 2022 Spring Update - WTW (wtwco.com). *See* Exhibit 2701 for a portion of this update.

[28] Order No. 20-473 at 108.

provides no such justification in this case for why these costs should be system allocated.

Additionally, Staff remains concerned about the precedent of allowing PacifiCorp to allocate its California wildfire risk to Oregon customers because of California's inverse condemnation statute and the benefits directly to Californians.[29] I am not an attorney, but it is my understanding that under California law, victims of a wildfire that is attributed to utility equipment can recover damages by suing the utility. This presents a potentially large amount of financial risk and the cost of insurance premiums to cover this risk that should be borne only by California customers.

Q. Given this discussion, is Staff revising its recommendations from its direct testimony on insurance?

A. Yes. Staff is no longer recommending the adjustments found in its direct testimony. However, for this rebuttal testimony, Staff recommends an adjustment of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Are there any additional comments you wish to make?

[29] Article I, Section 19 of The California Constitution provides the basis for recovery against government entities and public utilities via the theory of inverse condemnation. That section requires that just compensation be paid when private property is taken or damaged for public use. The courts have expanded inverse condemnation liability to include privately owned public utility companies transmitting power. Barham v. Southern Cal. Edison Co., (1999) 74 Cal.App.4th 744, 751.

A. To the extent that other intervenors are not referenced in this testimony, those parties did not comment on the topics covered in Jent/1200.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 399
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 2701

Non-CONF Exhibits in Support Of Rebuttal Testimony

August 11, 2022

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 361

OPUC Data Request 361

Advertising - 860-026-0022 (2)(c) describes Category C expenses as "Institutional advertising expenses, promotional advertising expenses and any other advertising expenses not fitting into Category "A," "B," or "D"." See response to SDR 104 (e), which states, "There are no Category C advertising expenses that are associated with a promotional activity or a promotional concession program".

(a) Reconcile and explain the statement above and the fact that Category C expenses are estimated to be $67,178 for Oregon.

(b) Resubmit a response that answers SDR 104 (e) and all of its subcomponents.

Response to OPUC Data Request 361

(a) There are $67,178 of expenses per Oregon Administrative Rules (OAR) 860-026-0022 (2) considered in Category C, Institutional advertising expenses and other advertising expenses not fitting into Category "A," "B," or "D." However, there are no Category C expenses that are considered Promotional Activities or Promotional Concessions (OAR 860-026-0010, 860-026-0015, 860-026-0025 and 860-026-0035).

(b) Please refer to the Company's response to subpart (a) above.

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 362

OPUC Data Request 362

Advertising - Please explain why in response to SDR 104 (f) it is stated, "The following programs did include advertising during Test Year [Blue Sky and Demand-Side Management Programs]," yet under the Blue Sky description it is stated, "The Company does not have budgeted advertising expenditures for this program."

Response to OPUC Data Request 362

The Company's response to Standard Data Request – OPUC 104 subpart (f) mistakenly omitted the word "not". The response to Standard Data Request - OPUC 104 subpart (f) should read:

"The following programs do *not* include advertising during the Test Year. Funds for these programs are collected through a separate tariff and not part of base rates."

The Company does not budget advertising expenditures at the level of detail requested.

UE 399 / PacifiCorp
April 6, 2022
OPUC Data Request 181

OPUC Data Request 181

Advertising and Promotions - What was the final test year expense for Category A, B, and C advertising in NWN's previous three rate cases?

Response to OPUC Data Request 181

The Company assumes that the reference to "NWN" is in error, and that the request is intended to be asking for advertising in PacifiCorp's previous three rate cases. Based on the foregoing assumption, the Company responds as follows:

PacifiCorp objects to this data request on the grounds that it seeks information that is outside the scope of this proceeding and not reasonably calculated to lead to the discovery of admissible evidence. The data requested here is already public information, readily available and is not included in the Company's general rate case (GRC). Subject to and without waiving the foregoing objections, PacifiCorp responds as follows:

Please refer to Attachment OPUC 181 which provides advertising expenses by category as requested from the Company's most recent three GRC. Note: Docket UE-263 was resolved through a full settlement, and Docket UE-246 was resolved through a partial settlement, where revenue requirement approved in each of those GRCs were settled-upon amounts. As such, the Company has provided the requested advertising expenses by category in the Company's direct filing for each of those dockets, but a final breakdown of individual advertising category expense in approved rates from each of the cases was not provided as part of the settlement.

PacifiCorp Response to DR 181 Attach is in electronic spreadsheet format only

PacifiCorp Revised Response to DR 176-1 1st revised is in electronic spreadsheet format only

Insurance Marketplace Realities

2022 Spring update

wtw

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Executive summary
Resilience amid disruption

If you're looking for precedents for what's facing our world and our industry today, you have to go back decades. It's been over half a century since large-scale armed conflict broke out in Europe. It's been decades since inflation hit levels we're seeing now. It's been over a century since the world faced a deadly pandemic, an ordeal we all hope is in its last significant chapters. In short, you have to go back a long way to find a moment with commensurate levels of disruption.

As the crisis in Ukraine continues, our first thought is about the resulting humanitarian crisis. With civilians suffering, the number of refugees swelling, and the hopes of a quick negotiated peace disappearing, our hearts go out to all those impacted by this tragic turn of events. Our second thought is about how we help our clients manage their personnel, investments, operations and businesses in this region. The global economic impact of the crisis and the sanctions against Russia is still a big unknown. In terms of insured losses stemming from the crisis, we estimate now that P&C insurers could be looking at something close to $15 billion. That's a big number, but to put it in perspective, 2021 brought over $130 billion in insured catastrophic losses.

Turning to inflation and the overall prospects for the North American economy, there are several factors at play. Some indications point to a leveling of inflation, but common household costs keep climbing – just ask anyone filling up their car at a gas station. Meanwhile, the future of interest rates adds to the uncertainty. The Fed is raising rates, as national economic attention moves from the pandemic to rising prices, but how fast and how far rates will go up remains to be seen. Other indicators give cause for concern. Home mortgage application recently fell to their lowest point in two years. The overheated home real estate market that took hold in the pandemic may be cooling off, and perhaps other parts of the economy will pull back with it.

These broad economic trends of course impact the P&C industry, and for more detail on how all that might play out, we include the article below, "Inflation, investment returns and new upward pressure on insurance rates from some of our industry analysts." But in the bigger picture we're happy to offer a bright spot in this otherwise dark moment in history. By several key measures, the insurance industry is in a better position than ever. Policyholder surplus has surpassed a rather astonishing one trillion dollars. Net income is at unprecedented levels. Return on equity (ROE) for insurers is also up significantly. The industry is more than ready to handle the $15 billion in losses the Ukraine crisis could yield.

For buyers, the marketplace still has its challenges, especially for less attractive risks. Rates are still going up in most lines, as reported below. But in most lines, increases continue to decelerate, and the market is stabilizing. The solid foundation for insurers should ultimately bode well for insureds.

Of course, much could change in the next six to 12 months. Disruption and uncertainty are the watch words of the day. But in our world, there's another watch word: resilience. In fact, that summarizes what we do for our clients: offer the perspective to respond to uncertainty, disruption and risk and help them keep moving toward resilience.

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Looking forward, looking back

The most eye-catching story when it comes to insurance rates remains with cyber. While the hard market gradually loosens its grip, cyber rates continue to spike — and spike higher. Last fall we predicted increases of 50% to 150%. Now we are forecasting 100% to 200%. Outside of cyber, conditions are slowly improving for commercial insurance buyers in North America. Increases are still the norm, but the deceleration of those increases is now at the point where a fair number of insureds can expect single-digit increases or even flat renewals for the first time in several annual cycles — as long as they can present a compelling risk picture to the marketplace.

We are, of course, a long way from a soft market. This issue marks the fifth in a row where the number of lines predicting rate decreases has come in at zero. Experts in 26 of our now 33 lines of coverage (we added architects and engineers this issue) are predicting that most buyers will face increases. But even here there are some breaks in the clouds: eight of those lines put the bottom end of their rate prediction at flat increases. And in 13 lines, half of the 26, the increases are forecast to be smaller.

Here are highlights from our spring 2022 predictions:

- Property is one of the lines where the bottom end of the rate prediction is flat — down from +2% to +10% for better risks. Less attractive risks can still expect to see +15%.
- Liability increases are expected to dip modestly, from a range of +5% to +12.5% to a range of +4% to +10%.
- Similarly, predictions of umbrella increases dipped (from a range of +10% to +30%) to <+20% for high hazard risks and from <+20% to <15% for low/moderate hazard risks.
- D&O is forecast to see some rate *decreases* in some best-case situations for the first time in several issues of this publication.
- Three lines that have been forecasting rate increases but now include the possibility of flat renewals are fidelity/crime, energy and D&O for financial institutions.
- Two lines moving in the opposite direction are terrorism and trade credit – perhaps not a surprise given the crisis in Ukraine. In these lines, predictions of small decreases for some have given way to predictions for flat renewals at best for trade credit, and increases in double digits for many buyers of terrorism and political violence cover.
- Similarly, two lines are calling for higher increases than in the fall edition: personal lines and life sciences.

In short, buyers will still be paying more for their insurance in most cases. But in most lines, with the notable exception of cyber, improvement is expected to continue through 2022 — unless inflation and/or the crisis in Ukraine end up turning the direction of the marketplace.

Market trends: lines facing increases, decreases or a mix*

Marketplace Realities issue	Decreases	Increases	Mix/flat
2022 spring update	0	26	7
2022	0	24	8
2021 spring update	0	30	1
2021	0	29	1
2020 spring update	0	23	5
2020	2	20	5
2019 spring update	2	14	9
2019	2	14	9
2018 spring update	2	10	10
2018	7	7	9
2017 spring update	10	6	7
2017	10	6	7
2016 spring update	9	8	5

*The 2022 spring update includes architects and engineers (A&E) for the first time. The 2022 edition includes middle market as a separate line of business. The 2021 spring update figures include marine hull/liability and marine cargo as separate lines. The 2021 figures include life sciences and alternative risk transfer predictions for the first time. The 2020 spring update figures reflect the addition of managed care errors & omissions as a separate line of business. The 2020 figures reflect the addition of personal lines and financial institutions as separate entries. The 2019 figures reflect the addition of marine, cargo and senior living/long-term care as separate lines of business. The 2018 spring update figures reflect the absence of marine in that issue; the 2017 figures reflect the addition of international coverage as a separate line, and the 2018 figures reflect the addition of product recall and the subtraction of employee benefits, which are no longer covered in this report. Casualty lines are discussed in one combined report but are included in this table as separate items (GL, umbrella/excess, auto and workers compensation).

For more insight on how you can prepare for a challenging marketplace, contact your local WTW representative.

Inflation, investment returns and new upward pressure on insurance rates

Our industry is indeed in a moment of great uncertainty. As of April 2022, the financial markets have been buffeted by several trends in addition to the crisis in Ukraine. A consensus is building that their combined impact on inflation will be more than transitory. We now seem to be on the cusp of a new era of higher interest rates and, for a time, higher inflation. A key question is for how long?

Higher interest rates and higher inflation generally lead to both moderate claims inflation, and in the near term, depressed investment returns – although higher interest rates will increase yields for invested premiums, they will also lower the value of fixed-rate bonds. These factors in turn lead to higher pricing in insurance markets, particularly in specialty business lines where replacement costs are driven by the prices of commodities and labor costs – both of which are rising.

Inflation expectations always encompass uncertainty. We outline three potential scenarios.

- The most benign is a transitory short spike in inflation, as labor and manufacturing bounce back quickly to meet post-pandemic demand levels. Given the elevated consumer price index reports for the last five months, this appears unlikely if not impossible.
- A stronger case can be made for a medium-term (two-year) rocky period of elevated inflation, as industrial activity (oil wells and mines, global manufacturing and cargo) and recalibrating labor markets get back in sync in a fast-moving global economy.
- A less likely case, in our view, includes a sustained period of higher inflation or stagflation. This would only come about if reaching a new equilibrium in material and labor markets takes longer than expected.

Regardless of how long and intense this period of inflation turns out to be, we expect it to have an impact on the insurance marketplace.

Rising rates and shrinking balance sheets

In response to inflationary pressures, the Federal Reserve has begun tightening monetary policy and raising interest rates. Many in our industry have not experienced such conditions.

From 2008 to 2015, the central bank, in response to the Great Financial Crisis – kept short-term rates just above 0% to spur growth and fortify damaged bank balance sheets. This significantly increased the money supply. Keeping rates so low for so long while growing the money supply raised the possibility of inflation.

By early 2016, the Federal Reserve began modestly raising rates, which appeared to be helping both to maintain economic growth and tame inflation expectations. Then, in March 2020, the global pandemic intervened to literally send everyone back home, close city centers, and shutter the economy as we knew it. The U.S. government injected a huge amount of money into the economy. The pandemic led to other economic turns as well.

A truly global event

The COVID-19 pandemic impacted mortality rates, mental and physical health and the worldwide economy. Now, with vaccination rates up and the pandemic hopefully waning, the economic aftereffects of the pandemic are becoming apparent.

As demand rises, there is supply-side impact as well.

Supply chain disruptions combined with reduced output levels at manufacturing facilities have decreased the supply of many industrial goods. The pulse of new and unplanned-for demand, along with the depressed supply, has shocked markets and led to significant upward pressure on prices.

This spike in demand has affected the auto, construction, and metal industries in particular.

The pandemic also brought a significant shift in the labor market. In the great resignation, as many as 4.5 million Americans left the workforce. With the economy opening back up and sparking more demand for labor, we are seeing modest to significant upward pressure on wages.

The combined effect of these economic and social forces would have been enough to push prices up. Then another unexpected event took place: Russia sent its armed forces into Ukraine.

Another global event

The ongoing crisis in Ukraine is clearly taking an unimaginable humanitarian toll. However, Russia is also a major energy supplier to Europe, and Russia and Ukraine together represent an important percentage of global wheat harvests. This energy disruption has helped push the price of crude oil from the $70 per barrel in December 2021 to nearly $120 per barrel in early March 2022.

The capital markets have experienced significantly higher levels of volatility, higher credit spreads and now a flattening of the U.S. yield curve. The latter is often seen as a predictor of an upcoming recession. Clearly, any sustained period of higher oil prices will increase the likelihood of a recession and hurt risk asset investment returns.

Impact on insurance

Impact on claims. A potentially short- to medium-term pulse of higher inflation will likely have a significant impact on expected claims, particularly for specialty lines, such as aerospace, commercial auto, construction, energy, marine cargo and marine hull. Increases in material replacement and repair costs, including labor costs, should be expected to a significantly raise insurer projections of future expected claims.

Impact on investment returns. The first of a likely series of rate hikes by the Federal Reserve has lifted short- to medium-term interest rates. The resulting higher yields for new investments may well be offset by the expected losses due to further increases in rates over 2022. Increased interest rates improve reinvestment yields for new premiums, but also reduce the value of the existing bond portfolio. The extent of this reduction will depend on the investment strategy employed, realization requirements and the accounting treatment of the portfolio. Additionally, the specter of higher inflation could lead to lower than expected or negative equity returns. Low projected returns across both bonds and equities for 2022 and 2023 due to the expected future increases in interest rates would obviously depress the investment returns across the investment portfolio for insurers.

Impact on pricing. Insurers facing claims inflation and depressed investment returns will likely consider higher and differentiated renewal prices.

These increases will depend on the tenor of the claims exposure. For shorter claims, conditions might benefit to some degree from slightly higher investment return assumptions due to higher yields, Medium-term to longer claims will be exposed to the higher risk associated with greater investment losses from medium-term bonds, as well as potentially depressed investment returns overall.

Insurer's prices may well reflect and anticipate both the higher expected claims inflation and lower expected investment returns, driving prices higher. The extent of the increases will depend at least in part on the impact of inflation dependency of a given claims stream.

Most of the lines in this report are predicting a continued easing of price increases, as the hard market of the last couple of years abates. But upward price pressures remain.

What to look for in 2022 and beyond

In addition to keeping an eye on the economic trends outlined above, policyholders can and must analyze their risks carefully and consider which risks they are willing to self-insure or alter coverage to address exposure to higher loss possibilities. Additionally, policyholders should assess the level and size of coverage required as asset prices and replacement costs may have risen. Buyers should engage in discussions with their insurers early on to avoid surprises in this highly uncertain and volatile period.

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Property

Rate predictions
Non-challenged occupancies:
Flat to +10%

Challenged occupancies:
+15% or more

Rate increases continue to decelerate, but the current inflationary spike in insurable values will sustain premium updraft.

Premium pain will continue through 2022, but premium increases for most insureds will likely be driven more by inflation raising insurable values than by increases in rate.

- The market is at an inflection point, whereby insurer balance sheets have been strengthened, and rate levels are beginning to keep pace with loss costs. As a result, rate increases will continue to slowly moderate throughout the year for most insureds.
- The bifurcated state of the market remains, as underwriters continue a highly discriminating approach to risk selection and pricing. For challenged occupancies – such industries as forest products, metals, waste management and food and beverage, and insureds with losses, protection challenges or cat exposures – double-digit rate increases are likely. On the flip side, those accounts that have performed well from a loss perspective, have reached a level of rate adequacy and have monetized retentions to rid themselves of attritional loss effects will find themselves in an advantageous position, with over subscription across all layers of the program becoming common.

Insured natural catastrophe losses for 2021 are estimated at $105 billion to $120 billion, according to several sources, making it the third highest nat cat loss year since 2011.

- While there was no mega event, the accumulation of catastrophes, which included hurricanes, floods, tornados and freezes, well exceeded the $70 billion average annual loss since 2011. So-called secondary or non-modeled perils contributed significantly to the industry loss record yet again. These perils include flood, tornados, hail, extreme temperatures, winter storms and wildfires.
- Whether attributable to climate change or greater insured values being in harm's way, the frequency and magnitude of these loss events are an increasing component of loss costs that must be priced for.

Valuation of assets used to produce a schedule of values will be the marquee issue for property insurance buyers this year. Without proper valuation, insureds may find themselves underfunded for retained risk, not properly purchasing adequate cat cover or setting sublimits improperly for key coverage elements.

- The challenges in asset valuation are set against a background of climate change-related natural disasters that have become more frequent and severe. This potential new normal could render current cat modeling out of date.
- Other factors include the global pandemic, which has caused severe supply chain issues from availability/price of materials, a shocking shortage of skilled workers in the labor market and longer-duration business interruptions.
- In determining replacement costs, no factor has more potential significance than inflation. According to a recent report, four leading construction cost indices saw upswings for the U.S. as of January 2022:
  - Marshall & Swift: +16% to +24.53%
  - RS Means: +15.83%
  - FM Global: +18.4%
  - ENR: +13.94%
- Property premiums are determined by a simple formula: rate X value. Although value derivation may be more fact- and data-based than rate, it is still a negotiation. However, proper, reliable asset valuation is essential. Accurate modeling outputs will help with setting of limits, deductibles, business continuity planning, claim adjustment/payment and, ultimately, pricing.

- While many buyers are concerned that underwriters will use the valuation issue as a reason to push for increased premiums (after three years of sustained rate increases for many), underwriters counter that changing valuations help determine probable maximum and/or maximum foreseeable losses as well as the return period loss estimates produced by catastrophe models — and must be part of their equation.
- Many underwriters recognize the factors at play causing spikes in values and will to some degree have an open mind on the issue. Some underwriters may be agreeable to trading rate for value to some degree, while others may be agreeable to a stair step, multiyear approach to getting the values right.
- For buyers perceived by the market as presenting inaccurate or out-of-date values, underwriters will push for the imposition of potentially claim-limiting clauses, such as the occurrence limit of liability clause, which restricts recovery to no more than 100% of the values reported for each location (thus negating the blanket aspect of most policies) and margin clauses, which similarly restrict recovery for the value reported for each location but add a buffer, typically of 10% – 25%.
- Some underwriters may also ask for an increase in deductibles commensurate with the spike in insurable values.
- As a result of the focus on valuations, many buyers may wish, or in many cases, be compelled to get an independent appraisal. This approach should go a long way toward providing the carriers with some concrete value accuracy and a comfort level when assessing an insured's risk.

Treaty reinsurance renewals were late to finish on January 1 and show signs of continued rate firming and withdrawal of capacity from catastrophe lines.

- Retrocessional markets and insurance linked securities (ILS), which play an important role in catastrophe reinsurance, held back capacity and were looking for a greater return on capital.
- Insurers will need to absorb these additional reinsurance costs, or more likely, attempt to pass them through, at least in part, to insureds.

COVID claims related to business interruption losses currently being litigated have thus far been substantially decided in favor of insurers.

- There are still hundreds of cases wending their way through the courts, and final outcomes are still years out.
- As insurers appear well-reserved for these potential claims, and infectious disease exclusions in property policies are now universal (like cyber exclusions), any further direct pricing impacts from COVID-related issues on property policies appear to be in the rear-view mirror.

Contingent business interruption exposures still concern underwriters due to continuing supply chain/ logistics constraints, lack of exposure information and unexpected losses.

- As a result, sublimit reductions are being imposed as well as requirements to fully name key customers and suppliers.
- Better data relating to contingent exposures leads to better outcomes in retaining customary sublimits.

Insurers are focused on perils that have increased in recent years.

- Given the frequency of severe convective storms (SCS) that continue to plague the southern U.S. along with wildfire in the west, carriers will continue to scrutinize these exposures and exert greater pressure to implement tornado/ SCS/hail and wildfire percentage deductibles, though they have yet to be mandated across the board.
- The spate of violent political events that occurred in 2020 and 2021 and sadly continue today reinforces the underwriter's desire to maintain vigilance around the peril of strikes, riots and civil commotion (SRCC). Many insureds may find this peril sublimited or, in some cases, subject to higher deductibles, particularly for retail risks.

Underwriters continue to push for the implementation of company/carrier policy forms in lieu of manuscript policies.

- Carrier forms typically appear to be more standard in the single carrier universe, but on large shared and layered accounts, the manuscript remains the most common approach.
- In some cases, carriers will assert that a broader capacity offering can be garnered with a company/carrier form, but cracks in the armor are appearing.

What can insureds do to prepare for upcoming renewals? The simple answer is that the need to differentiate risk has never been greater. Property is not a one-size-fits-all market; carriers are scrutinizing submissions more closely than ever. Key elements for a successful renewal are:

- Start early and take control of the renewal with a commitment to broad data collection and data quality.
- Increased information will help buyers more accurately model any changes (e.g., reduction in limit or increased retention) and help assure that risk management strategies reflect organizational risk appetite or corporate philosophy.
- Analytics provide important guidance as buyers align offerings in the marketplace to their rapidly shifting risk transfer needs. Cat modeling should be conducted annually at a minimum but, certainly, additional runs should be sought if substantial exposure changes present themselves during a policy term.
- Insureds should also consider alternative structures, such as parametric programs, to complement a traditional insurance plan. A parametric contract could provide immediate liquidity in the event of a covered loss while the loss adjustment for the traditional program is processed.
- Buyers need to distinguish themselves from their peers, especially in challenged occupancies. Risk managers must help tell this story and provide the necessary data to satisfy underwriters' insistence on robust underwriting information.
- Underwriter meetings are encouraged; telling a story of mitigation efforts, improved loss control measures and disaster recovery/business interruption plans remains critical in differentiating a buyer's risk. Risk managers need to manage stakeholder expectations as rate increases continue; they should consider creative solutions and alternative structures to mitigate the total cost of risk.

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CASE: UE 399
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF CONF EXHIBIT 2702

CONF Exhibits in Support
Of Rebuttal Testimony

August 11, 2022

UE 399 / PacifiCorp
July 28, 2022
OPUC Data Request 586

OPUC Data Request 586

CONFIDENTIAL REQUEST – Advertising - See Reply Testimony PAC/2000 Cheung/80 which shows Table 6 and Table 7. PAC added the column to staff's original figures titled Reason for Expense.

[CONFIDENTIAL BEGINS]

(a) [redacted]

(b) [redacted]

[CONFIDENTIAL ENDS]

Response to OPUC Data Request 586

The Company assumes that the reference to "PAC" is intended to be a reference to PacifiCorp. Based on the foregoing assumption, the Company responds as follows:

(a) Please refer to the table below:

FERC Account 909 - Category C Advertising Expenses

[redacted]

UE 399 / PacifiCorp
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OPUC Data Request 586

(b) Please refer to the tables provided below:

FERC Account 909 - Reclassified Category A Advertising Expenses

[redacted]

FERC Account 909 - Reclassified Category B Advertising Expenses

[redacted]

FERC Account 909 - Reclassified Category C Advertising Expenses

[redacted]

[redacted]

UE 399 / PacifiCorp
July 28, 2022 OPUC
Data Request 578

OPUC Data Request 578

CONFIDENTIAL REQUEST - See Reply Testimony PAC/2000 Cheung/16. It is stated, **[CONFIDENTIAL BEGINS]**

[redacted]

(a) [redacted]

(b) [redacted]

(c) [redacted]

[CONFIDENTIAL ENDS]

Confidential Response to OPUC Data Request 578

[CONFIDENTIAL BEGINS]

(a) [redacted]

(b) [redacted]

UE 399 / PacifiCorp
July 28, 2022 OPUC
Data Request 578

[redacted]

[CONFIDENTIAL ENDS]

(c) Please refer to Attachment OPUC 578-2.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 399 / PacifiCorp
July 28, 2022 OPUC
Data Request 578-1

CONFIDENTAL

[redacted]

PacifiCorp Response to DR 578-2 is in electronic spreadsheet format only

UE 399 / PacifiCorp
July 28, 2022
OPUC Data Request 583

OPUC Data Request 583

CONFIDENTIAL REQUEST – Insurance - See Reply Testimony PAC/2000 Cheung/24-25. It is stated,

[CONFIDENTIAL BEGINS]

[redacted]

(a) [redacted]

(b) [redacted]

[CONFIDENTIAL ENDS]

Response to OPUC Data Request 583

(a) [redacted]

(b) [redacted]

UE 399 / PacifiCorp
July 28, 2022 OPUC
Data Request 583

[redacted]

PacifiCorp Response to DR 583 Attach is in electronic spreadsheet format only

PacifiCorp Response to SDR 69-1 is in electronic spreadsheet format only

OR UE 399 PROTECTED INFORMATION SUBJECT TO GENERAL PROTECTIVE ORDER Confidential Attachment OPUC 069-2

OPUC 069

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Page 2

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PacifiCorp Response to AWEC DR 16 is in electronic spreadsheet format only

CASE: UE 399
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2800

Rebuttal Testimony

August 11, 2022

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

A. My name is Mitchell Moore. I am a Senior Utility Analyst employed in the Rates, Finance and Audit 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. I sponsored opening testimony in Exhibit Staff/1300.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to reply testimony by PacifiCorp staff witness Allen Berreth in PAC/1600 regarding wildfire mitigation and vegetation management expense.

Q. Did you prepare any exhibits for this rebuttal testimony?

A. Yes. I prepared Exhibit Staff/2801 which provides Data Request (DR) responses cited herein.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Wildfire Mitigation and Vegetation Management Expense 2

ISSUE 1. WILDFIRE MITIGATION, VEGETATION MANAGEMENT EXPENSE

Q. Please summarize your position from opening testimony.

A. In opening testimony, Exhibit Staff/1300, I recommended an adjustment of ($6.5 million) in Test Year expense for wildfire mitigation and vegetation management (WMVM). This adjustment would reduce the Company's Test Year expense approximately 9 percent - from a forecast of $70.8 million to $64.3 million. PacifiCorp's filing proposes to increase its WMVM expense by more than 37 percent over the base year.

In addition, PacifiCorp's Oregon jurisdictional expense for this category is increasing at a much higher rate than related expense in PacifiCorp's other jurisdictions. In calendar year 2019, Oregon's portion of vegetation management and wildfire mitigation expense was 66.4 percent of the total Company expenditure. In the Test Year, the Company proposes an amount that represents 80.5 percent of total company expenditure for this category. Staff believes that PacifiCorp has not met its burden of justifying the extraordinary increase in expense, nor provided a satisfactory explanation as to why Oregon expense is increasing at a much higher rate than other jurisdictions.

Q. How did staff calculate its proposed adjustment?

A. Oregon's recent historical portion of WMVM expense ranged from 66.4 percent in 2019 to 77.3 percent in 2020; and, Oregon's proportion was 75.2 percent in the base year. I took a simple average of these historical expense ranges and calculated a Test Year expense to represent 73 percent of total company expense.

Q. Why did Staff choose this method to propose an adjustment?

A. In its opening testimony PacifiCorp indicated that the increase in expense was necessary to address the growing risk of wildfires in Oregon.[1] The Company points to plans to increase the minimum clearance distances for pruning within the Fire High Consequence Areas (FHCA); transitioning from a four-year pruning cycle to the three-year pruning cycle; and conducting annual pole cleaning.

Staff assumes that the Company is not only addressing the growing risk of wildfires in Oregon, but also addressing the growing risk of wildfires in its other jurisdictions. Absent any analysis or information from the Company to explain why Oregon expense would be increasing at a much high rate than other jurisdictions, Staff finds it reasonable to use a historical average of relative expense to project the Test Year.

Q. What is the Company's response to Staff's proposed adjustment and analysis?

A. In PacifiCorp's reply testimony, PacifiCorp rejects Staff's adjustment as unwarranted, as it explains that its proposed expenses are, "based on a budget that identifies where and how the money will be spent. This enabled the

[1] See UE 399 PAC/700, Berreth/22.

Company to accurately determine the percentage of total 2023 expenses that are assigned to Oregon."[2]

Q. Has the Company provided information that would enable Staff to determine its proposed expense as just and reasonable?

A. No. Staff attempted to discover how PacifiCorp builds its "budget that identifies where and how the money will be spent," and how the Company was able to, "accurately determine the percentage of total 2023 expenses that are assigned to Oregon."

In DR No. 579, Staff asked for a detailed description of how the Company developed its budget for Oregon and for each of its other jurisdictions. The Company's response was high-level and vague, and, did not provide any insight as to how the company identifies "how and where the money will be spent."[3]

In DR No. 580, Staff asked for an itemized budget for these expenses for the test year, for Oregon and for each of the Company's other jurisdictions. The Company's response was essentially a non-response. It simply reiterated its total projected budgets for the states of Oregon, California and Utah.[4]

Q. What is the Company's explanation with regard to the higher rate of increased expense?

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[2] See UE 399 PAC/1600, Berreth/3.
[3] See Exhibit Staff 2801, Moore/1: Company response to Staff DR No. 579.
[4] See Exhibit Staff 2801, Moore/2: Company response to Staff DR No. 580.

A. The Company asserts in reply testimony that "more of the Company's Oregon facilities are in forested, high consequence areas relative to other states, so Oregon has a greater need for increased wildfire mitigation investment."[5]

Q. Does Staff find this explanation persuasive?

A. No. This statement merely explains why Oregon might have a larger share of total Company expenses in wildfire mitigation and vegetation management. It does not sufficiently explain why the *rate* of increase in expense would go from 66.4 percent in 2019 to 80.4 percent in the 2023 Test Year. Staff asked the Company to provide a basis and rationale for why Oregon's WMVM share of total company expense was increasing at a faster rate. The Company response reiterated this argument, and provided a table to demonstrate the number of overhead line miles contained within an FHCA:[6]

State	**Overhead FHCA/HFTD**
Washington	20
Oregon	**2667**
California	1159
Utah	676
Wyoming	0
Idaho	0
Total	**4522**
Oregon percent of total:	
59.0%	

5 See UE 399 PAC/1600, Berreth/3.
6 Staff Exhibit 2801, Moore/5: Company response to Staff DR No. 581.

As demonstrated in the above table, Oregon overhead lines contained within an FHCA represent approximately 59 percent of the total throughout PacifiCorp's service territories. This, along with PacifiCorp's assertion that the Oregon FHCA is more densely forested, could provide a reasonable explanation as to why Oregon WMVM expense has historically represented an average of 73 percent of total company expenditures. But it does not explain why that percentage should rise to 80.4 percent, as PacifiCorp proposes in its Test Year.

Q. Did Staff agree in Opening Testimony that Test Year expense "are consistent" with Commission guidance in the Company's last rate case and Wildfire Protection Plan?

A. No. This question refers to a statement made by Company witness Alan Berreth in PAC/1600, Berreth/2, which was referring to an error in Staff/1300, Moore/5, line xx. The statement should read Base Year, not Test Year. Staff had reviewed the Company's base year expenditures and concluded that they were consistent with Commission guidance in UE 374 and in the Company's Wildfire Protection Plan.

Q. What is Staff's position with regard to PacifiCorps' proposal to defer WMVM expenses not spent?

A. In its reply testimony, PacifiCorp recommends the Commission require PacifiCorp to track and report WMVM expenditures and defer unspent dollars.[7] Staff does not oppose this recommendation. Staff does think that deferring any

[7] See UE 399 PAC/1200, Steward/13.

unspent monies would provide the Commission the option to either have the monies returned to customers, or be retained by the Company for later WMVM project expenditures, the following year. Staff recommends the latter alternative as the first alternative may provide the utility the incentive to find ways to spend the monies rather than returning the monies to customers.

Q. Does Staff have a change to its recommendation?

A. No. Staff maintains its recommendation to adjust the Company's WMVM Test Year expense by ($6.4 million). PacifiCorp has the burden to demonstrate that its proposed costs are just and reasonable. With a proposed increase of 37 percent in WMVM expense, and an increase in the rate of expense relative to other jurisdictions, PacifiCorp should demonstrate why this is reasonable. It has not done so in this case.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 399
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2801

Exhibits in Support
Of Rebuttal Testimony

August 11, 2022

OPUC Data Request 579

Wildfire Mitigation and Vegetation Management - Referencing PAC/1600, Berreth/3: Please provide a detailed description of how PacifiCorp developed its wildfire mitigation and vegetation management "budget that identifies where and how the money will be spent". Please provide this information separately for both Oregon situs/allocated, and individually for each of the other states in which the Company operates.

Response to OPUC Data Request 579

PacifiCorp develops the budget for the entire system and then it is allocated consistent with the 2020 Multi-State Inter-Jurisdictional Cost Allocation Methodology (2020 Protocol). Distribution costs are situs assigned to each state, while transmission costs are system allocated across the various states. Wildfire mitigation and vegetation management develops a work plan to identify the circuits being worked within a year and what technical specifications there are for the work. That work plan is then used to estimate budget based on historical spend or quotes from vendors.

OPUC Data Request 580

Wildfire Mitigation and Vegetation Management - Referencing PAC/1600, Berreth/3: Please provide an itemized wildfire mitigation and vegetation management budget for the test year, separately for Oregon situs/allocated, and individually for each of the other states in which the Company operates.

Response to OPUC Data Request 580

PacifiCorp does not have wildfire mitigation plans (WMP) filed in Wyoming and Idaho as there are no state regulations requiring WMPs to be submitted for these two states. PacifiCorp does produce a WMP for Washington, however the area is very small and there are no operations and maintenance (O&M) expenses to provide for Washington's budget relating to this request.

Please refer to the below table which provides a summary of state-specific wildfire mitigation and vegetation management costs planned for 2023 for Oregon, California, and Utah, by function. Distribution amounts are assigned 100 percent to each state respectively, and transmission amounts are allocated using a system-allocation factor. The amounts reflected in the table below represent each state's respective share of transmission expenses. Only Oregon's situs expense, and Oregon's share of transmission expense is included in the Company's request for recovery in this general rate case (GRC). Other states' assigned and allocated costs are not part of this GRC:

	Oregon	**California**	**Utah**
Distribution/Situs	$68.5 million	$15.6 million	$7.4 million
Transmission/System	$2.4 million	$0.2 million	$4.1 million

Please refer to the below tables which provide an itemized breakdown of the distribution/situs-allocated expenses for Oregon, California and Utah:

Oregon		
Investment Category	**Programs / Incremental Scope Included**	**Oregon Distribution ($ million)**
WMP Distribution (Non-Vegetation Management)	• Annual asset inspections in the FHCA • Transition from a 10-yr to a 5-yr detail inspection cycle in the FHCA (100% increase in annual detailed inspections) • Situational awareness (Described above in testimony) • Stakeholder and community engagement • Plan monitoring	$4.2
WMP Vegetation Management - Distribution	• Annual vegetation management inspections in the FHCA • Radial pole clearing of subject poles in the FHCA • Implementation of new maintenance cycles	$15.3
Non-WMP Vegetation Management – Distribution		$49.0
TOTAL		**$68.5**

California		
Investment Category	**Programs / Incremental Scope Included**	**California Distribution ($ million)**
WMP Distribution (Non-Vegetation Management)	• Situational awareness (Described above in testimony) • Stakeholder and community engagement • Plan monitoring • Customer Impact Mitigation Programs (Medical Baseline Portable Battery Program & Generator Rebate Program) • Plan Monitoring	$2.3
WMP Vegetation Management - Distribution	• Annual vegetation management inspections in the HFTD • Radial pole clearing of subject poles in the HFTD	$3.7
Non-WMP Vegetation Management – Distribution		$9.6
TOTAL		**$15.6**

Mitigation Program	**Utah Distribution ($ million)**
Advanced Protection and Controls	$0.3
Environmental	$0.3
Inspections and Corrections	$1.4
Situational Awareness	$3.1
Vegetation Management	$2.3
Total Distribution O&M	**$7.4**

OPUC Data Request 581

Wildfire Mitigation and Vegetation Management - Referencing Staff/1300, Moore/6:

(a) Please provide a basis and rationale that explains why Oregon's portion of wildfire mitigation and vegetation management costs are increasing at a faster rate than its costs in other jurisdictions.

(b) Please explain why Oregon's portion of total company wildfire mitigation and vegetation management costs increased from 66.4 percent in 2019 to 80.5 percent of total company costs in the test year forecast.

Response to OPUC Data Request 581

(a) Referencing the opening testimony of Public Utility Commission of Oregon (OPUC) staff witness, Mitch Moore, Exhibit Staff/1300, specifically page 6 (Wildfire and Vegetation Management Expense), wildfire risk is increasing in PacifiCorp's jurisdictions. However, PacifiCorp's Oregon service territory has the largest Fire High Consequence Areas (FHCA), or areas of risk, therefore there has been more spend in Oregon than other states. In addition, the volume of trees or tree density within the FHCA in Oregon is higher compared to other jurisdictions which directly correlates with increased spend. More vegetation management work is being conducted in Oregon due to these factors. Please refer to the table below which provides a breakdown of each state and their associated overhead circuit line miles within an FHCA / high-fire threat district (HFTD) which demonstrates that the larger number of line miles in the FHCA is in Oregon:

State	Overhead FHCA/HFTD Line Miles
Washington	20
Oregon	2667
California	1159
Utah	676
Wyoming	0
Idaho	0

(b) In 2019, PacifiCorp was at the beginning stages of performing wildfire vegetation work but with enhanced focus and alignment in strategies, PacifiCorp has expanded programs and costs in wildfire mitigation and vegetation management in order to address the growing risk of wildfires in Oregon. All vegetation management work will transition to a three-year cycle and specifically target risk reduction in the FHCA with three distinct strategies:

First, PacifiCorp vegetation management will conduct annual vegetation inspections on all lines in the FHCA, with correction work also completed based on inspection results,

Second, PacifiCorp will use increased minimum clearance distances for distribution cycle work completed in the FHCA, and

Third, PacifiCorp plans to complete annual pole clearing on subject equipment poles located in the FHCA.

CASE: UE 399
WITNESS: Ming Peng

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2900

Rebuttal Testimony

August 11, 2022

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

A. My name is Ming Peng. I am a Utility Analyst employed in the Rates, Finance, and Audit Division of the Oregon Public Utility Commission (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.

Q. What is the purpose of your testimony?

A. My testimony is intended to rebut depreciation expense of the reply testimony provided by Ms. Cheung of PacifiCorp.

Q. Did you prepare any exhibits for this rebuttal testimony?

A. Yes. I prepared exhibit Staff/2900, consisting of 7 pages.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Depreciation Expense 2

ISSUE 1. DEPRECIATION EXPENSE

Q. With regard to Cheung's rebuttal testimony, what areas do you intend to address?

A. Cheung has made three assertions regarding Staff's net salvage percent adjustments, with respect to the depreciation expense in this case.

1. It would not be appropriate to attempt an approximated update to these parameters in this proceeding. (PAC/2000, Cheung/42).
2. "Dave Johnston and Naughton plants, are not in fact part of the Company's proposal for coal life updates in this case." Also, "Staff did not produce calculations in support of the three units for which depreciable lives are being proposed to be extended in this case, Craig Unit 2 (and Common facilities), and Hayden Units 1 & 2." (PAC/2000, Cheung/42).
3. In calculating the new annual accrual based on the proposed reductions to negative net salvage, Staff incorrectly reduces future accruals by the entirety of the proposed negative net salvage percentage, rather than just the decremental change, from the current value to the proposed value resulting in an overstatement of the impact to depreciation expense. (PAC/2000, Cheung/43).

I will address each of these issues in that order.

Q. Do you agree with Cheung's first assertion above that it would not be appropriate to update the parameters in this proceeding?

A. No. I do not. ORS 757.140(1), states: "Each public utility shall conform its depreciation accounts to the rates so ascertained and determined by the commission. The commission may make changes in such rates of depreciation from time to time as the commission may find to be necessary."

Q. Why do you consider necessary making adjustments on net salvage percent in this case?

A. For the ratemaking approach, my adjustment intends to reduce depreciation expenses by making the net salvage percent less negative, based on the fact Oregon customers have paid much more and much earlier compared to the other five states. In my opening testimony, Exhibit Staff/1400, Peng/5:

> Historically, Oregon has had higher depreciation rates and expenses because the Oregon Commission in Order Nos. 08-327 and 08-427 did not allow PacifiCorp to extend the expected lifespan beyond the designed life expectancy for coal-fired power plants for the Oregon-based, system-wide depreciation portfolio.

Because of this, Oregon had much shorter coal life and much higher depreciation rates, including a decommissioning cost. Oregon customers should not pay something that Oregon already paid for.

Q. Do you agree with Cheung, who has recommended "the depreciable lives of these units have not been proposed to change since approved in docket UE 374 and should not be included in Staff's calculation for updates to negative net salvage in its proposal?" (PAC/2000, Cheung/43).

A. No. I do not. I did not propose to change the coal life in this case. My calculation was based on the coal life from the Commission Order 20-473, Docket No. UE 374.

Q. Is your calculation based on Order 20-473?

A. Yes. The service life for coal power plants (coal life) has been extended in Docket No. UE 374 compared to the coal life that was authorized by OPUC.

Cholla Unit 4: I made no adjustment on Cholla Unit 4.

Dave Johnston and Naughton Plants: Cheung said: "[T]he Company notes that Dave Johnston and Naughton plants, included in Ms. Ming Peng's analysis, are not in fact part of the Company's proposal for coal life updates in this case." (PAC/2000, Cheung/42). I made an adjustment to these plants because their net salvage percent has changed due to their coal lives being modified in Order 20-473. I did not review the coal life issue in UE 399. Any new changes that the PAC proposed are not currently authorized. My review is based on the coal life that has been authorized in Order 20-473.

Colstrip: PAC said: "[W]hile part of the depreciable life update in this case, its life is being proposed to be shortened by 2 years, from 2027 to 2025, and is not being extended." (PAC/2000, Cheung/42). Based on the existing Order 20-473, I cancel my adjustment on Colstrip plant. I missed the line that links for Colstrip calculation during the review.

Craig Unit 2 (and Common facilities), and Hayden Units 1 & 2: Based on the existing Order 20-473, there are no changes on coal life and net salvage percent. Therefore, I did not make the adjustments.

Please note, if the parties reach agreement on a coal life adjustment, I would review the reasonableness for net salvage percent for these plants.

Q. Do you agree with PAC's third assertion that Staff incorrectly reduces future accruals by the entirety of the proposed negative net salvage percentage, rather than just the decremental change, from the current value to the proposed value resulting in an overstatement of the impact to depreciation expense?

A. No. I do not. The purpose of my adjustment is for Oregon to pay the reasonable depreciation cost. When I find the depreciation expense allocated to Oregon is not fair to Oregon customers, an adjustment is reasonable to make.

Q. Do you identify the method that PacifiCorp used to calculate the net salvage percent for those the coal life being extended in Order 20-473?

A. Yes. From what I have seen in the company's calculation, PAC simply increased the net salvage percent by making the rates more negative for those coal plants that the service life has been extended for. The net salvage increases on assets were mainly for FERC accounts on Boiler Plant Equipment. As a result, the depreciation expense increased accordingly. In short, the more negative the net salvage percent, the higher the depreciation expense will be.

Please note, my adjustment on net salvage is only for Oregon-based calculations. I do not have any intention to change the net salvage for the five other states.

Q. Do you agree with PAC's counterargument that there does not need to be any adjustments on net salvage percent and depreciation expenses in UE 399?

A. No. I do not. My adjustment is for the rate-making approach in revenue requirement. If the depreciation cost allocation is not good, it should be adjusted.

Q. Does this conclude your rebuttal testimony?

A. Yes.

CASE: UE 399
WITNESS: Paul Rossow

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3000

Rebuttal Testimony

August 11, 2022

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

A. My name is Paul Rossow. I am a Utility Analyst employed in the Rates, Finance, and Audit 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. I sponsored Staff Exhibits Staff/1500-1504.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to PacifiCorp's (Company) Reply Testimony on the issues of Memberships and Subscriptions, and Meals and Entertainment and Awards Expenses.

Q. Did you prepare an exhibit for this rebuttal testimony?

A. No.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Memberships and Subscriptions 2
Issue 2. Meals and Entertainment and Awards 5

ISSUE 1. MEMBERSHIPS AND SUBSCRIPTIONS

Q. Please summarize your adjustment from your Opening Testimony and PacifiCorp's response.

A. In my Opening Testimony, I propose a downward adjustment of ($185,528) in "Memberships and Subscriptions" expense, based on my analysis as described in my testimony.[1] This category of expense is comprised of: (1) Memberships and Subscriptions and (2) Dues. In PacifiCorp's Reply Testimony, the Company argues that Staff's adjustment creates a duplicative adjustment of disallowed items incurred in the months of January 2021-June 2021 and pursues costs from July 2021-December 2021 that is not included in the Base Period.[2]

Q. Is Staff updating its opening testimony position adjustment regarding the disallowance of ($185,528) related to memberships and subscriptions methodology?

A. No. Staff still proposes using an alternative Base Year consisting of 12 months, ending December 2021 by using the Company's Results of Operations (ROO) ending December 2021.

Q. Does Staff agree with PacifiCorp's assertions that the proposed adjustment creates a duplicative adjustment and includes costs not in the Company's Base Period.

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1 Staff/1500, Rossow/4-5.
2 PAC/2000, Cheung/32.

A. No. To capture an accurate calendar year 2021 Base Year level of non-labor expenses for membership and subscriptions, Staff utilizes known costs reported in the Company's December 2021 ROO report filed in April 2022, which reflects the most recent historical information available and allows for a comparison of the Base Year with historical and future years of the same months. In developing an alternative 2021 Base Year, Staff includes the same specific costs incurred in the months of January 2021-June 2021 and from July 2021-December 2021 to capture an appropriate Oregon escalated Test Year level of costs in a downward adjustment of ($185,528).

Q. Did PacifiCorp provide an Oregon Test Period adjustment for memberships and subscriptions?

A. Yes. Before escalation, PacifiCorp included an adjustment for this expense on an Oregon allocated Test Period amount of ($146,082), which is included in my Opening Testimony, Exhibit Staff/1500, Rossow/4, Memberships and Subscriptions. Escalating this Test Period adjustment with the Company's IHS Markit indices results in a decrease to the Oregon Test Period expense of ($153,502).

Q. Did Staff propose an alternative Oregon Test Period adjustment for memberships and subscriptions?

A. Yes. Before escalation, Staff prepared a Test Period adjustment in the amount of ($169,313), which results in an additional downward adjustment of ($23,231) from the Company's Test Period adjustment. Next, Staff applied the All-Urban Consumer Price Index of 6.8 percent and 2.6 percent, respectively, to arrive at a Test Year escalated adjustment of ($185,528).

Q. What does Staff recommend?

A. Staff recommends that the Commission decline PacifiCorp's proposed historical Base Period of 12 months ended June 2021 methodology associated with Memberships and Subscriptions expense in this general rate case and adopt Staff's alternative Base Period taken from the Company's December 2021 ROO, resulting in an Oregon escalated Test Period downward adjustment of ($185,528). The final adjustment then is the difference between $185,528 and the Company $153,502, meaning the effective Staff adjustment is ($32,026) to expense.

ISSUE 2. MEALS AND ENTERTAINMENT AND AWARDS

Q. Please summarize your adjustment from your Opening Testimony, and PacifiCorp's response.

A. Using the same methodology through which Staff's Memberships and Subscriptions adjustment was calculated, Staff arrived at a downward adjustment of ($28,192) in Operations and Maintenance (O&M) non-labor expense, as described in my Opening Testimony.[3] In PacifiCorp's Reply Testimony, the Company argues that my adjustment is duplicative of disallowances from January 2021-June 2021 and seeks to remove expenses from July 2021 December 2021 that is not part of the Base Period. [4]

Q. Has Staff's position changed regarding the disallowance of ($28,192) in O&M non-labor expenses related to meals and entertainment and awards?

A. No. To capture an accurate calendar year 2021 Base Year level of non-labor expenses for Meals and Entertainment and Awards, Staff utilizes known costs reported in the Company's December 2021 ROO report filed in April 2022, which reflects the most recent historical information available and allows for a comparison of the Base Year with historical and future years of the same months. In developing an alternative 2021 Base Year, Staff includes the same specific costs incurred in the months of

[3] Staff/1500, Rossow/10-11.
[4] PAC/2000, Cheung/34.

January 2021-June 2021 and from July 2021-December 2021 to capture an appropriate Oregon escalated Test Year level of costs in a downward adjustment of ($28,192).

Q. Did PacifiCorp provide an Oregon Test Period adjustment for Meals and Entertainment and Awards?

A. Yes. Before escalation, PacifiCorp included an adjustment for this expense on an Oregon-allocated Test Period amount of ($20,671), which is included in my Opening Testimony, Exhibit Staff/1500, Rossow/8, Meals and Entertainment and Awards. Escalating this Test Period adjustment with the Company's IHS Markit indices results in a downward a to the Oregon Test Period expense of ($21,721).

Q. Did Staff propose an alternative Oregon Test Period adjustment for meals and entertainment and awards?

A. Yes. Before escalation, Staff proposes a Test Period adjustment in the amount of ($25,728), which results in an additional downward adjustment of ($5,057) from the Company's Test Period adjustment. Next, Staff applied the All-Urban Consumer Price Index of 6.8 percent and 2.6 percent, respectively, to arrive at a Test Period escalated adjustment of ($28,191).

Q. What does Staff recommend?

A. Staff recommends that the Commission decline PacifiCorp's proposed historical Base Period of 12 months ended June 2021 methodology associated with Meals and Entertainment and Award expense in this general rate case and adopt Staff's alternative Base Period taken from the

Company's December 2021 ROO, resulting in an Oregon escalated Test Period downward adjustment of ($28,191). The final adjustment then is the difference between $28,191 and the Company $21,721, meaning the effective Staff adjustment is ($6,470) to expense.

Q. Does this conclude your testimony?

A. Yes.