SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT BOARD MEETING NOTICE AND AGENDA

SPECIAL BOARD OF DIRECTORS

Friday, January 31, 2025, 9:30 AM

Zoom Webinar Link (view only, no participation):
https://srpnet.zoom.us/j/85258939349?pwd=KTOMMjyxPLLNFr4NDjo3EYhf0QDaeT.1

SRP Administration Building
1500 N. Mill Avenue, Tempe, AZ 85288

Call to Order
Invocation
Pledge of Allegiance
Roll Call

1. Proposed Adjustments to the SRP Standard Electric Price Plans and Proposed Adjustments to the Fuel and Purchased Power Adjustment Mechanism (FPPAM) (Times are Approximate and Subject to Change)

   A. 9:30 AM: Opening Remarks .... PRESIDENT DAVID ROUSSEAU
   B. 9:40 AM: Management Presentation .... VARIOUS
   C. 11:15 AM: Presentations by Management Consultants .. MICHAEL MACE, PFM FINANCIAL ADVISORS; and MICHAEL KAGAN, CONCENTRIC ENERGY ADVISORS
   D. 11:45 AM: Board Consultant Presentation .... BRUCE CHAPMAN, CHRISTENSEN ASSOCIATES
   E. 12:30 PM: Initial Public Comments (2 minutes per commentor)...VARIOUS

2. Adjourn (No later than 1:30 PM) ....PRESIDENT DAVID ROUSSEAU

Please note that additional Public Comment times will be available at the February 6 and 11 Board meetings

Members of the public shall refrain from making any inappropriate comments while attending the meeting or addressing the Board. Disruptive activity from the audience, being loud, clapping, stomping of feet, or any similar demonstrations including any signage are also prohibited. Violations of this rule may result in removal from the meeting.

The Board may vote during the meeting to go into Executive Session, pursuant to A.R.S. §38-431.03 (A)(3), for the purpose of discussion or consultation for legal advice with legal counsel to the Board on any of the matters listed on the agenda.

The Board may go into Closed Session, pursuant to A.R.S. §30-805(B), for discussion of records and proceedings relating to competitive activity, including trade secrets or privileged or confidential commercial or financial information.

Visitors: The public has the option to attend in-person or observe via Zoom and may receive teleconference information by contacting the Corporate Secretary's Office at (602) 236-4398. If attending in-person, all property in your possession, including purses, briefcases, packages, or containers, will be subject to inspection.

Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle

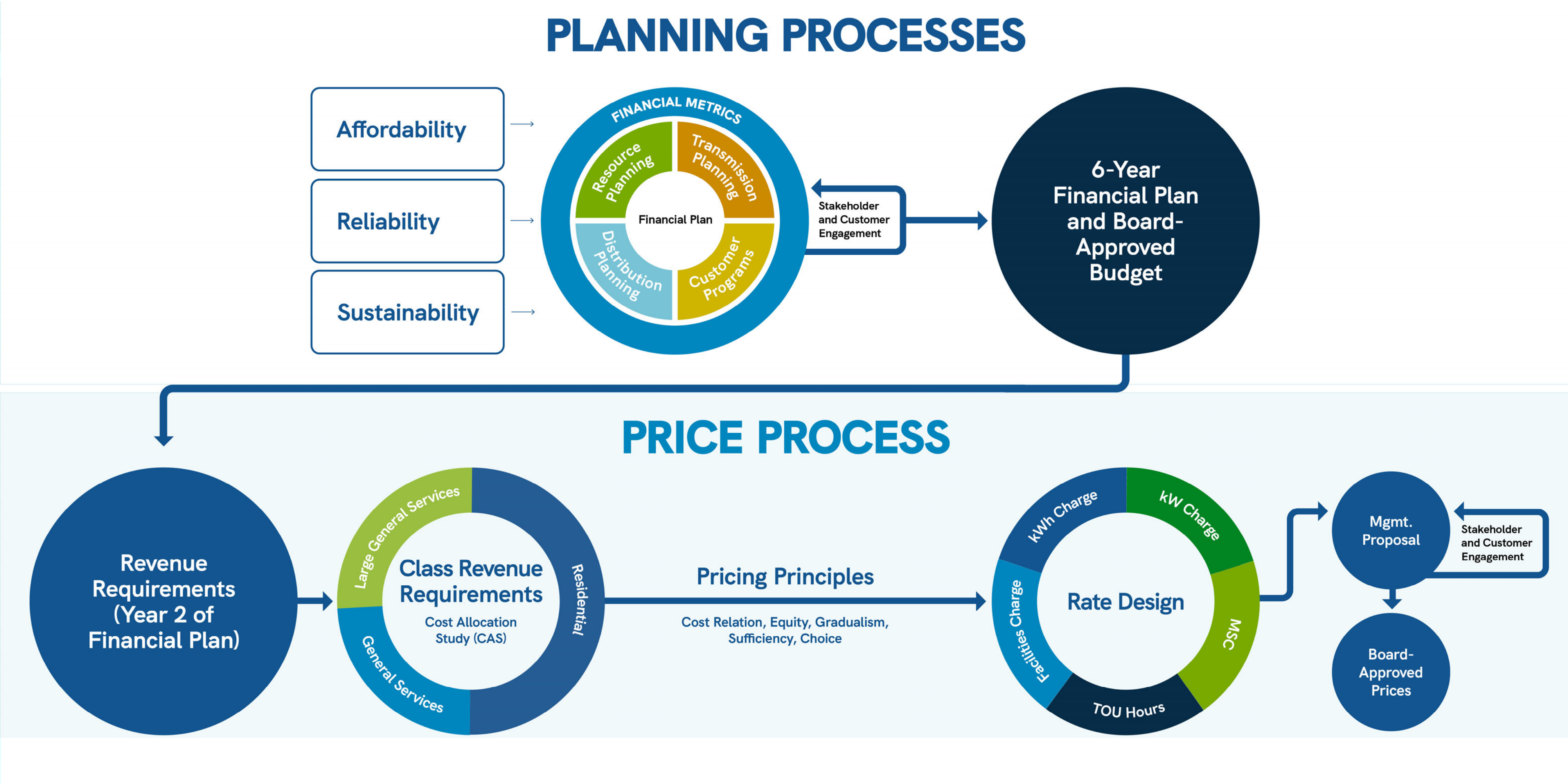
January 31, 2025

Brian Koch

Associate General Manager & Chief Financial Executive

Salt River Project

- One of the nation’s largest public power entities
- Community-based, not-for-profit utility
    - No equity investors (stockholders)
    - Customers ultimately pay for costs to provide electric service
    - Solid credit ratings (Aa1 & AA+)
- SRP is customer-focused
    - Award-winning customer service
    - Industry-leading reliability


PLANNING PROCESSES
Affordability
Reliability
Sustainability
FINANCIAL METRICS
Resource Planning
Transmission Planning
Financial Plan
Distribution Planning
Customer Programs
Stakeholder and Customer Engagement
6-Year Financial Plan and Board-Approved Budget
PRICE PROCESS
Revenue Requirements (Year 2 of Financial Plan)
Large General Services
Residential
General Services
Class Revenue Requirements
Cost Allocation Study (CAS)
Pricing Principles
Cost Relation, Equity, Gradualism, Sufficiency, Choice
kWh Charge
kW Charge
MSC
TOU Hours
Facilities Charge
Rate Design
Mgmt. Proposal
Stakeholder and Customer Engagement
Board-Approved Prices

2025 Price Process Objectives

- Limited revenue increase
- Simplified Residential price plan portfolio
- Increase assistance to limited-income customers
- Align TOU hours with evolving costs
- Address common solar customer concerns
- Protections for existing customers from new large load investments

John Tucker

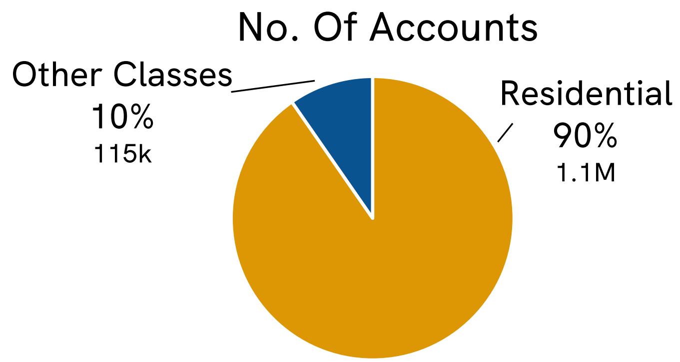
Sr. Director, Financial Strategy

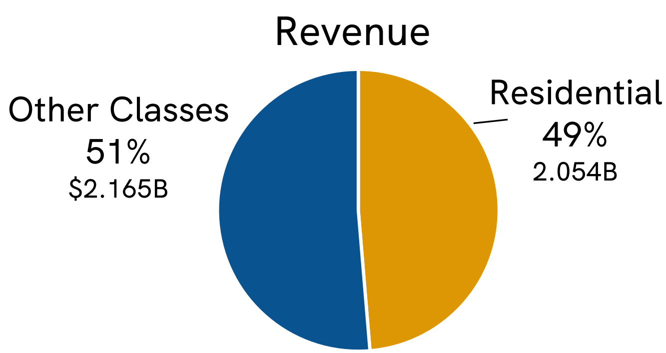
SRP Board Pricing Principles

These are the pricing principles the Board follows when making pricing decisions

Gradualism	Cost Relation	Choice	Equity	Sufficiency
Changes should be evolutionary, not revolutionary (avoid large price adjustments)	Prices need to reflect the cost of service	Pricing options should be provided to help customers manage their energy costs	Customers should pay their share of the costs SRP incurs on their behalf	Prices need to maintain SRP's financial health

Annual Revenues & Customer Accounts





Data from Financial Plan 2025/Fiscal Year 2026

	No. of Accounts
Basic	540,948
M-Power	147,840
TOU	328,289
Solar	56,775
Total Residential	1,073,852
Total Other Classes*	115,117

*Includes Commercial, Pumping, Lighting, and Large Industrial Classes

	Economy Price Plan – Current	Economy Price Plan – Proposed
Participants	82k	135k**
Eligible	175k**	275k**

**Estimated

Pricing Proposal Overview

Price Increase Overview:

- **2.4% Net Increase:** Maintains SRP's financial health, supports investments in the grid.
- **Prices Changes below Pace of Inflation:** Average annual price increase of 2.3% vs. 3.0% inflation over the past 10 years.
- **Favorable Peer Comparisons:** SRP remains in lowest quartile of peer utility prices.

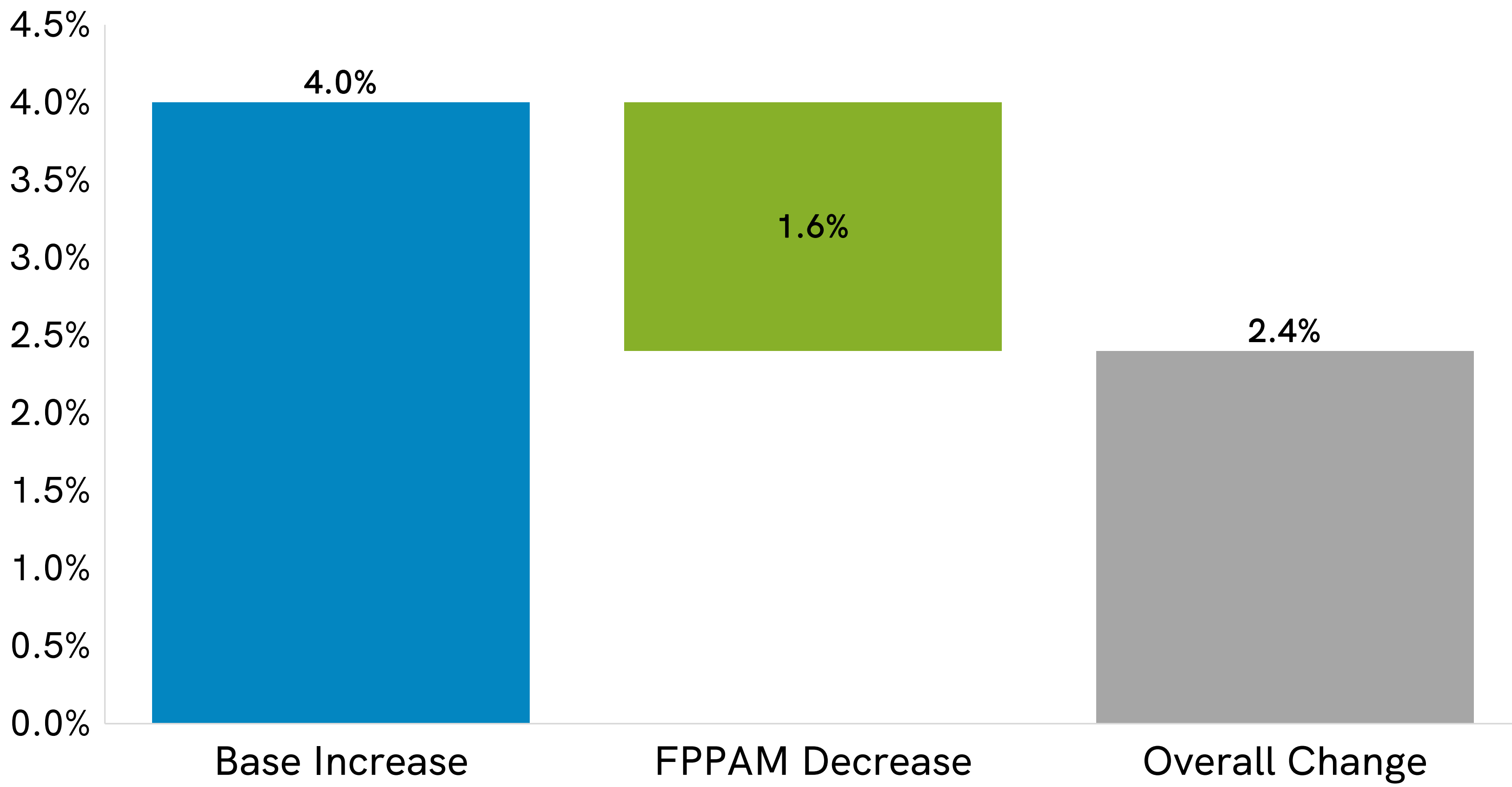
Customer Benefits:

- **Simplified Residential Portfolio:** Basic, M-Power, plus two time-of-use (TOU) options for all customers, including those with solar. Freeze remaining TOU plans with up to four-year transition period.
- **Updated Time-of-Use Hours:** Pass to customers the benefits of abundant low-cost, low-carbon utility scale solar and market prices, with 50%+ cheaper energy from 8am to 3pm for all (non frozen) TOU plans; align on-peak hours with higher cost periods.
- **Help for Those in Need:** Increased discount and broader eligibility for limited-income customers.
- **Improved Experience for Residential Solar Customers:** The new portfolio simplifies the process for rooftop solar customers without reintroducing cost shifts. Same price plans, Monthly Service Charge, TOU hours, and delivered energy charges as customers without solar, with no additional grid access fees; market-based export rate.
- **Cost Protection for Existing Customers:** Protect existing customers from costs of new industrial loads by requiring a minimum bill from those customers.
- **Delayed Implementation:** November 2025

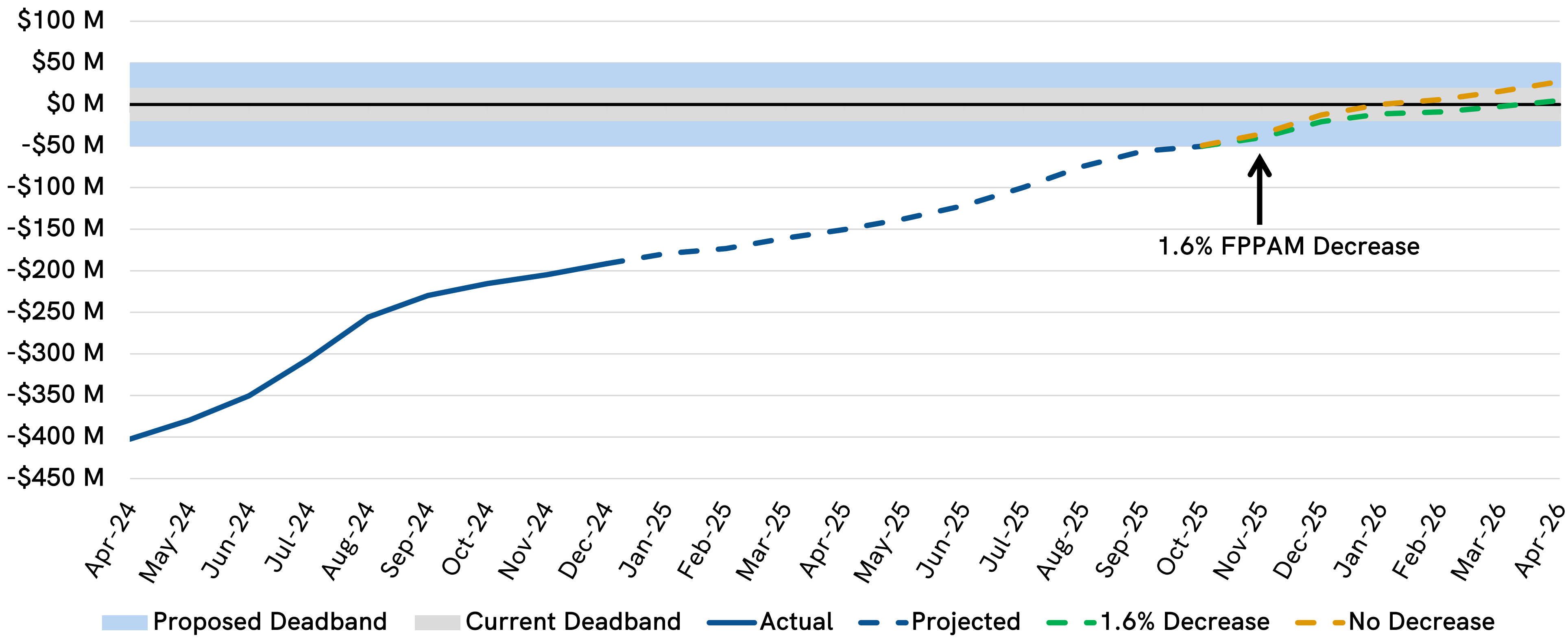
Other Proposed Changes

- **Fuel & Purchased Power Adjustment Mechanism (FPPAM):** Price reduction, deadband increase to $50M, and TOU-differentiated pricing
- **Modifications to Transmission Costs Adjustment (TCA):** Allow to more quickly adapt to changes impacting retail and wholesale transmission rates
- **> 69kV Transmission Cost Allocation:** Reduction to transmission component
- **Riders:** Streamline SRP's Rider Portfolio

Proposed Revenue Changes

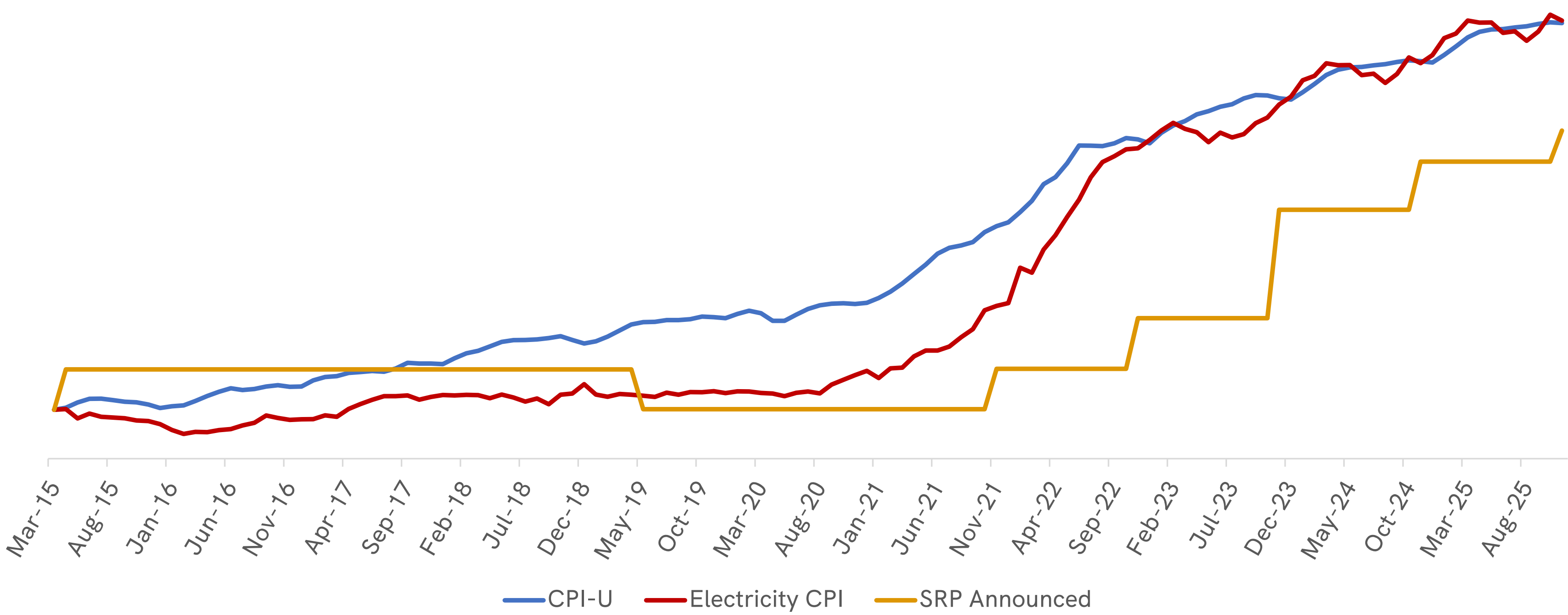


Projected Fuel & Purchased Power Adjustment Mechanism (FPPAM) Balance



SRP Prices vs Inflation Since 2015

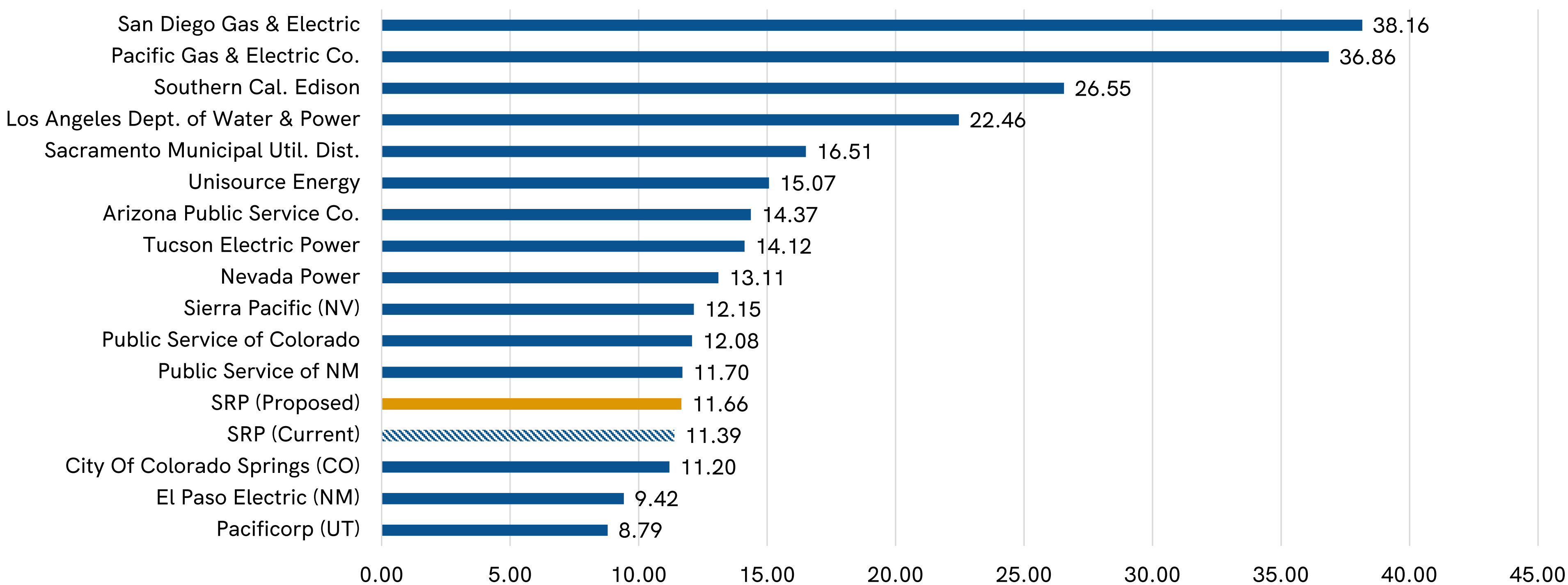
SRP's retail rates have increased at a pace less than inflation over the last 10 years



SRP Announced reflects permanent price changes from April 2015-Present. 2.4% projection made to reflect proposed Nov 2025 increase.
CPI-U and Electricity CPI Electricity based data from Apr 2015-Nov 2024 and projected forward for Dec 2024-Nov 2025

Price Comparison by Company – Overall (cents per kWh)

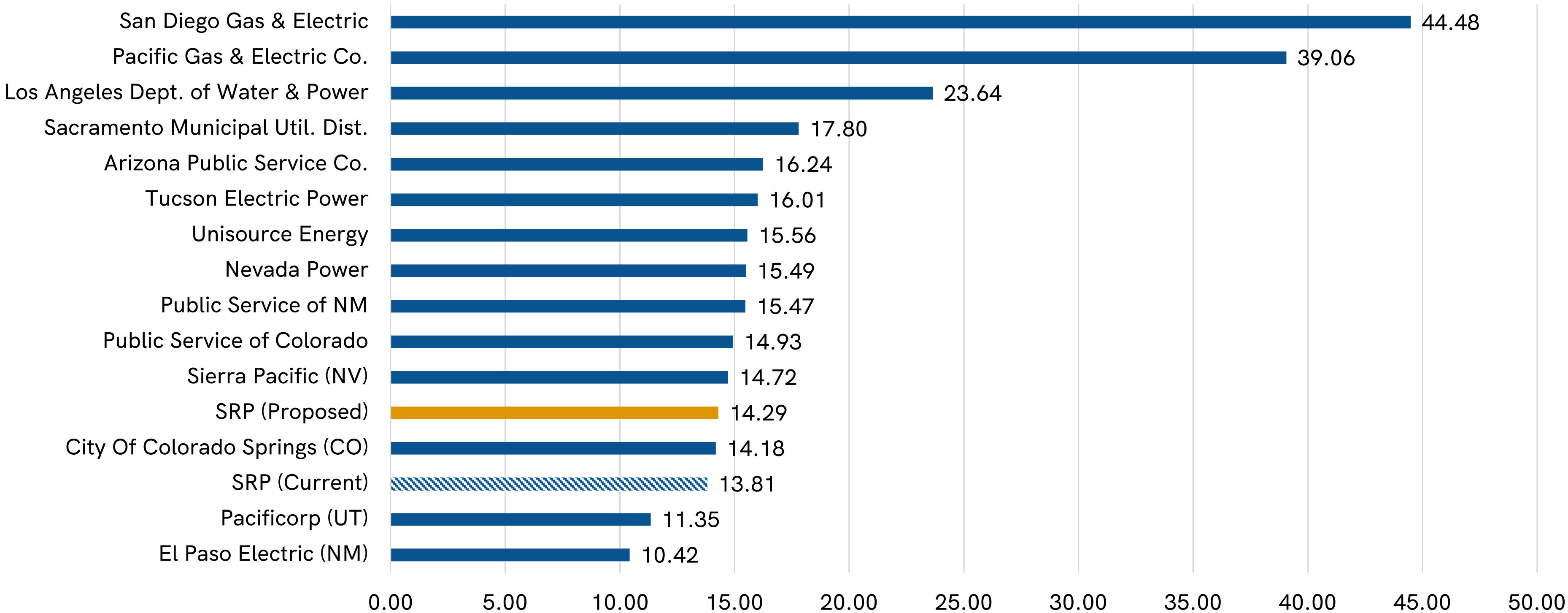
The Proposal keeps SRP within the lowest quartile of peer utility prices



Source: Dept. of Energy EIA-826 Reports for a rolling 12 months through Sep 2024.

Price Comparison by Company – Residential (cents per kWh)

The Proposal keeps SRP within the lowest quartile of peer utility prices



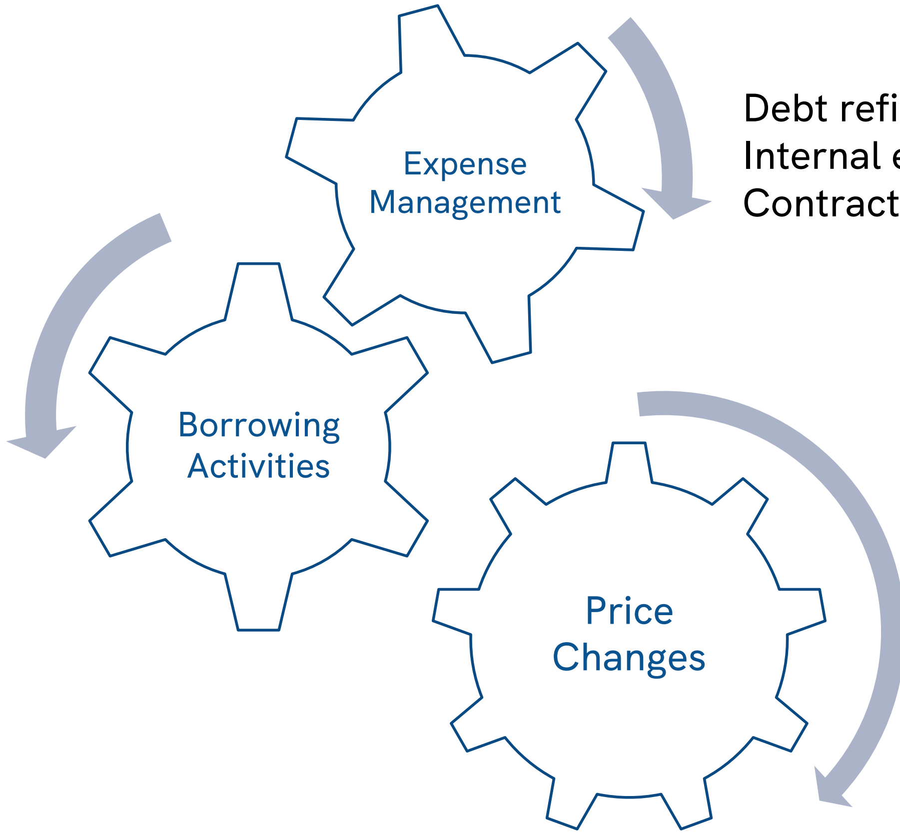
Source: Dept. of Energy EIA-826 Reports for a rolling 12 months through Sep 2024.

Danielle Jackson

Director, Financial Planning & Analysis

Three Levers To Manage Finances

Starts with expense management; borrowing and/or pricing actions can make up cash shortfalls

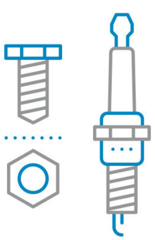


Debt refinancing
Internal efficiencies
Contract renegotiations

Revenue Need

Replacing aging infrastructure to maintain reliability

- Upgrades to transmission substations
- Plant Betterments at Palo Verde Nuclear Generating Station and Gila River Generating Station

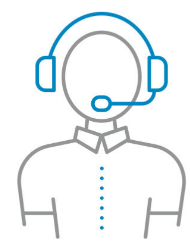


Adapting to an evolving power grid to meet sustainability and decarbonization goals

- Purchase of additional ownership in Palo Verde Nuclear Generating Station
- Constructing Copper Crossing Energy and Research Center

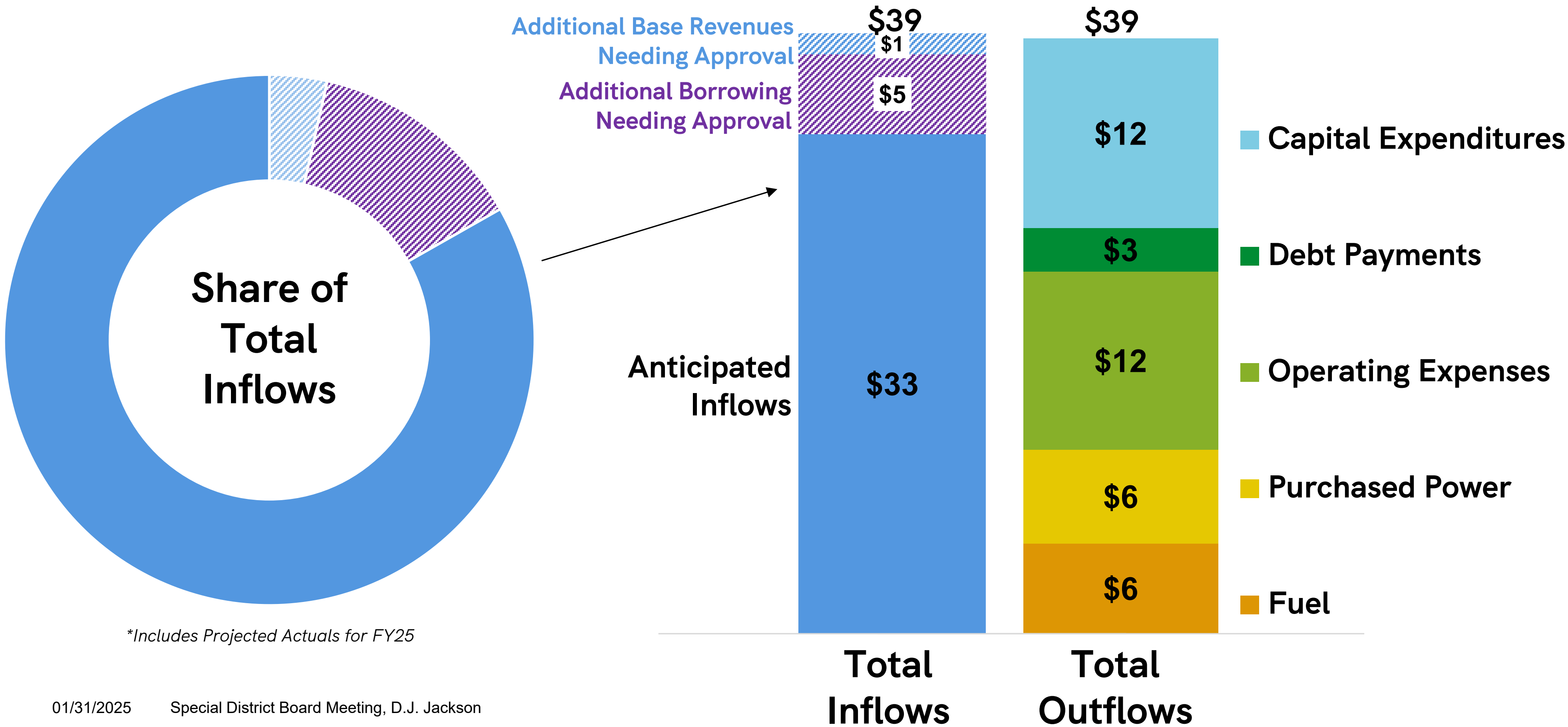
Enhancing customer programs and services

- Modernization of legacy Billing applications (Customer Modernization Program)
- Meters for Customer Growth including Solar growth & transitioning Elster meters to L+G meter



Revenue Need – Projected FY25-30 Cash Inflows and Outflows* ($B)

To pay for latest financial estimates, there are still significant funds that need approval



*Includes Projected Actuals for FY25

Brandon Shoemaker

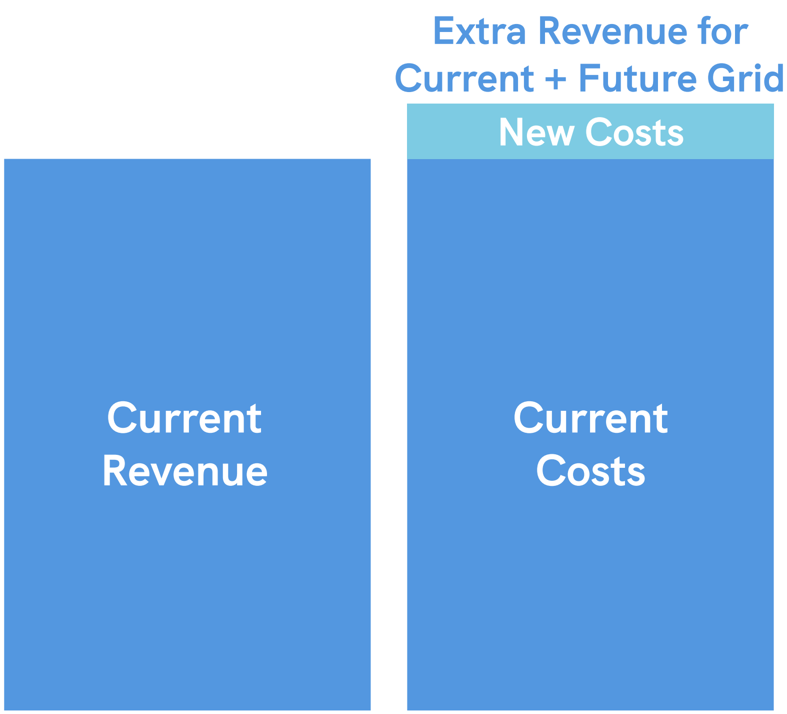
Director, Corporate Pricing

2025 Pricing Proposal Supporting Documents

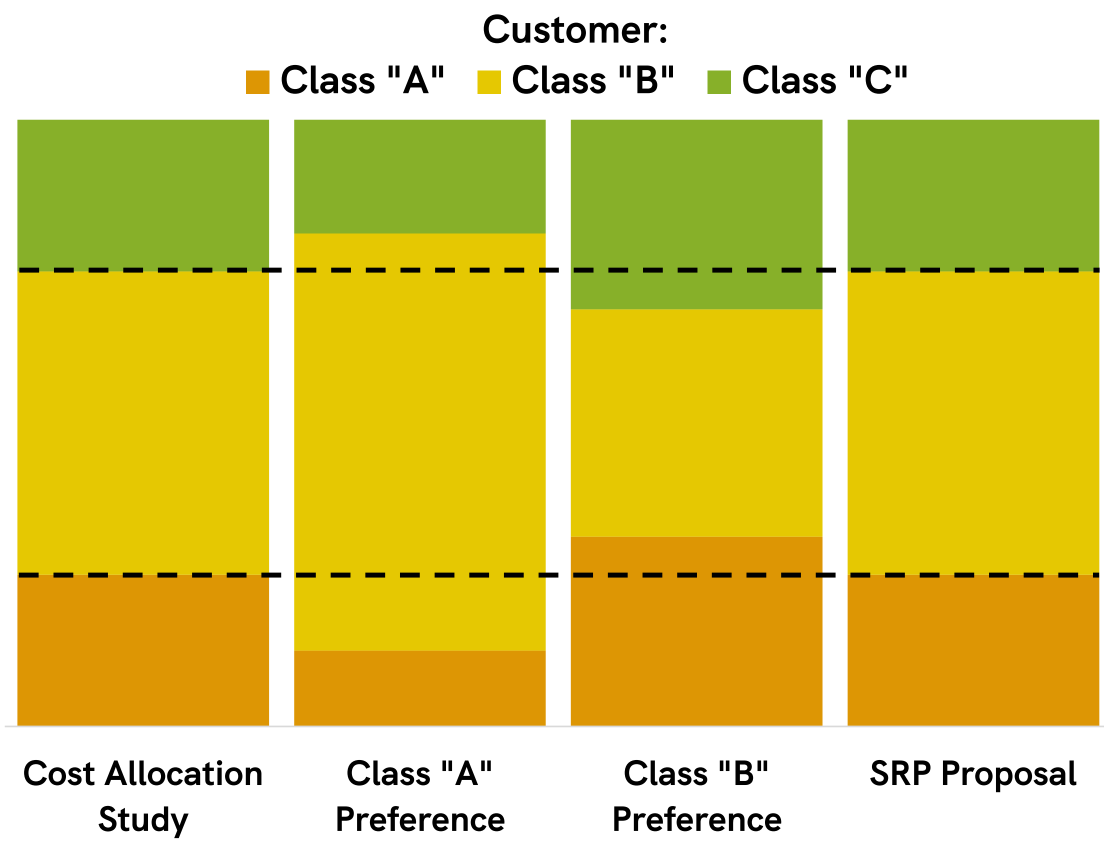
- The formal proposal and supporting documents are incorporated into this presentation by reference:
  - Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle (Amended and Restated)
  - Appendix A to Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle (Amended and Restated)
  - Cost Allocation Study in Support of Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle
  - Derivation of Proposed Changes to SRP's Transmission and Ancillary Services Prices Effective November 1, 2025

Pricing Principles and Price Process

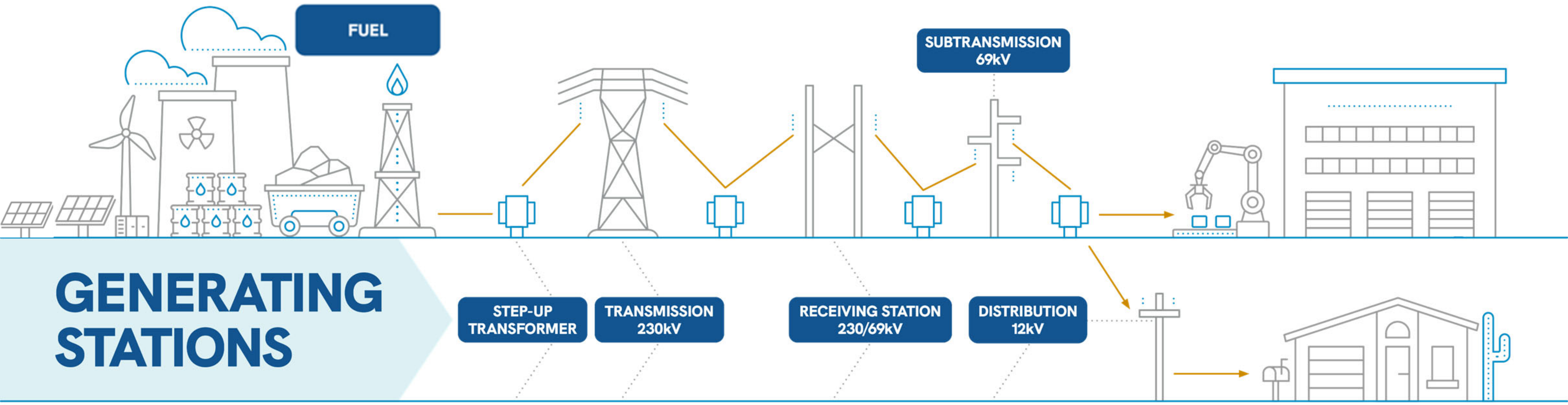
Determine Revenue Requirement



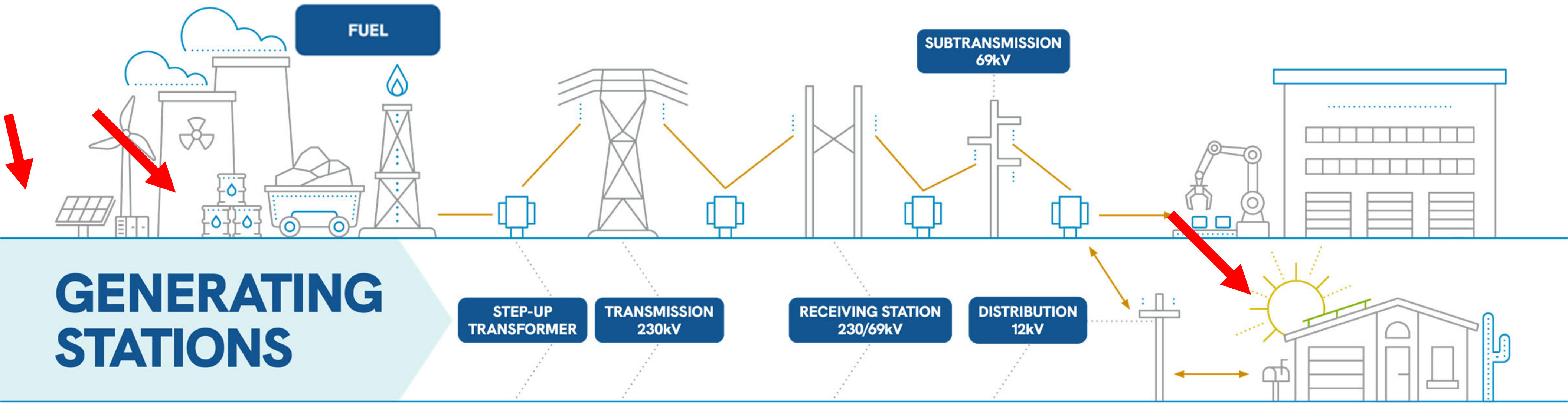
Determine Cost Allocation Across Customers



The Grid without Distributed Energy Resources

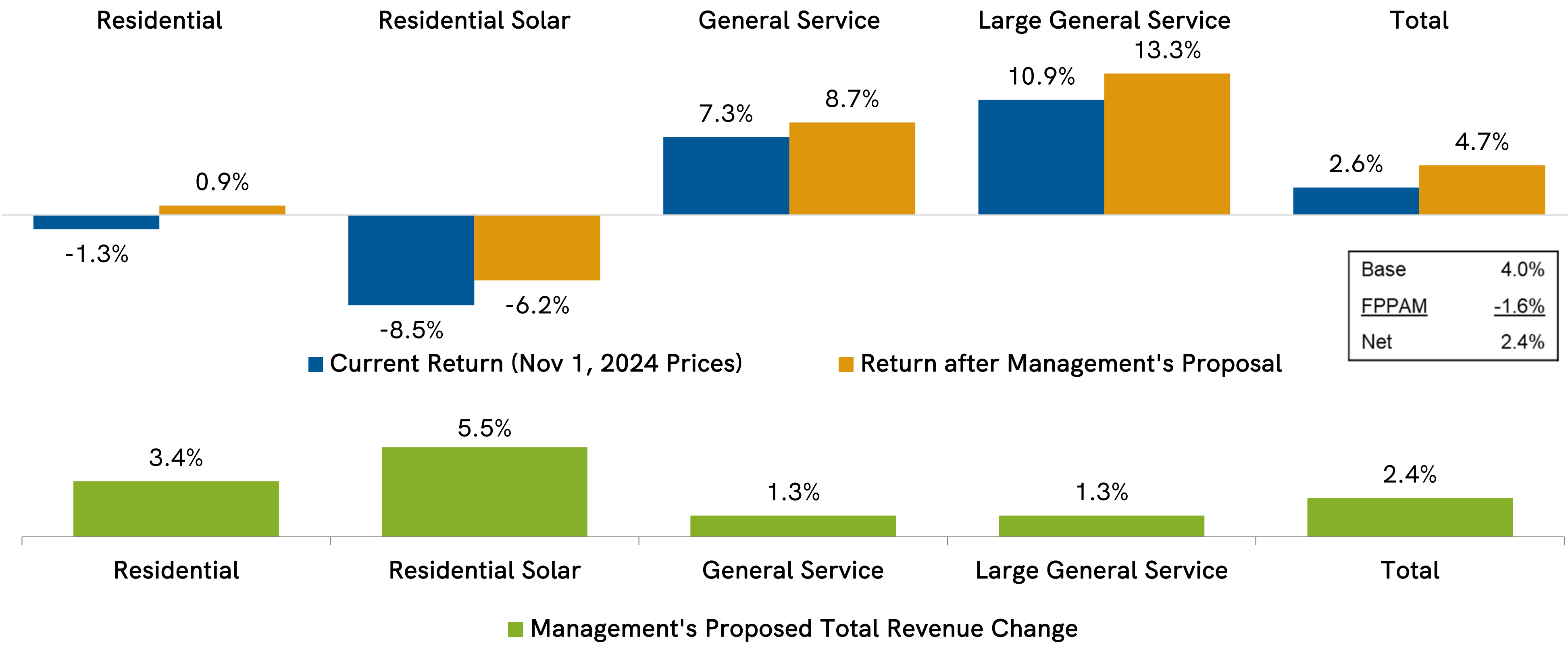


The Grid with Distributed Energy Resources



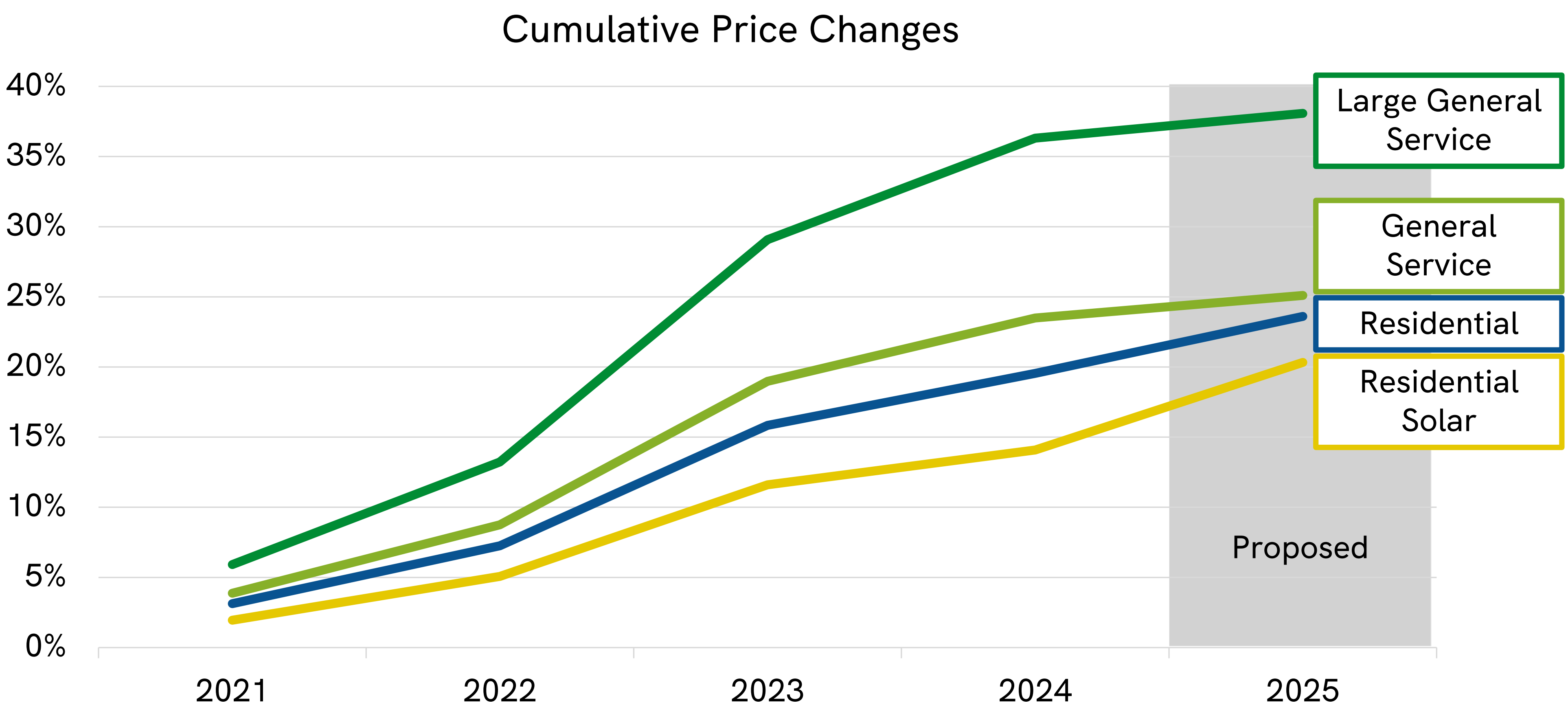
Proposed Average Adjustment Varies by Class

Being mindful of Board Pricing Principles of Gradualism, Cost Relation, Choice, Equity, and Sufficiency

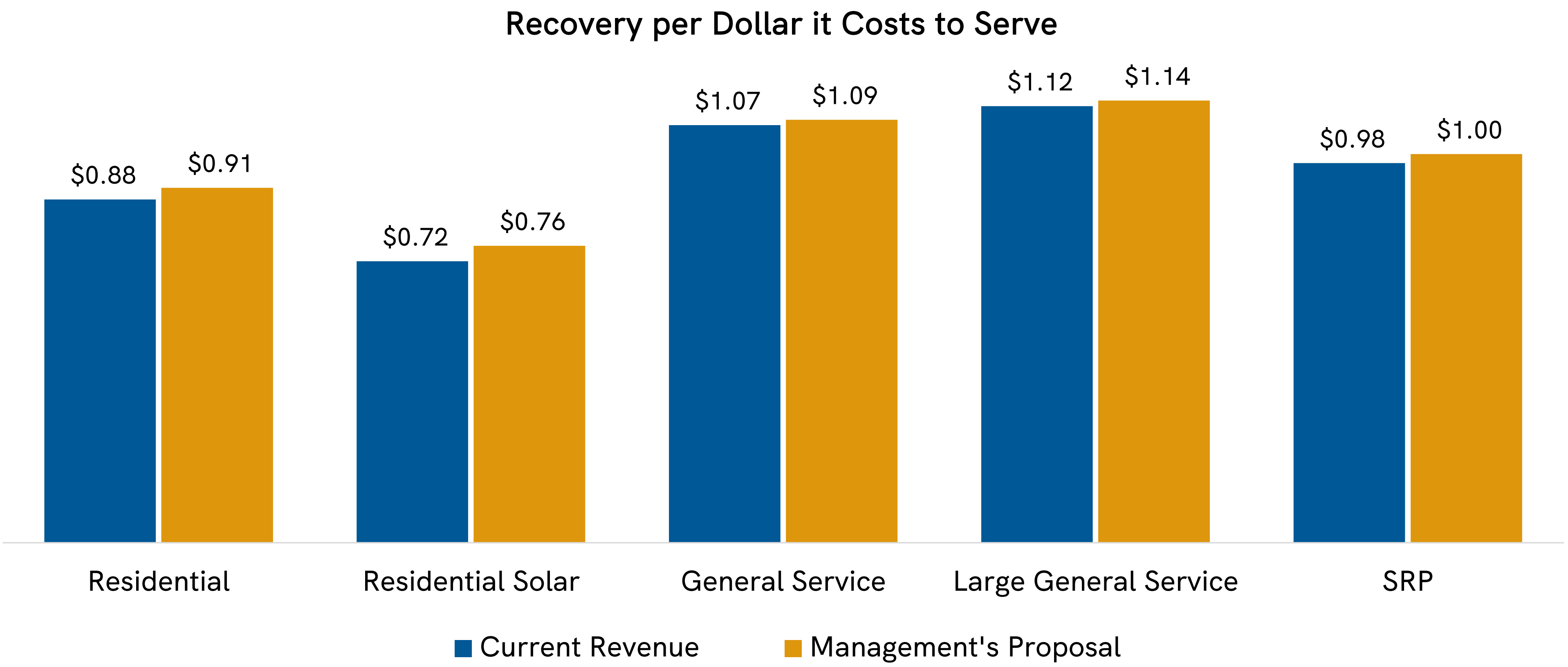


Base	4.0%
FPPAM	-1.6%
Net	2.4%

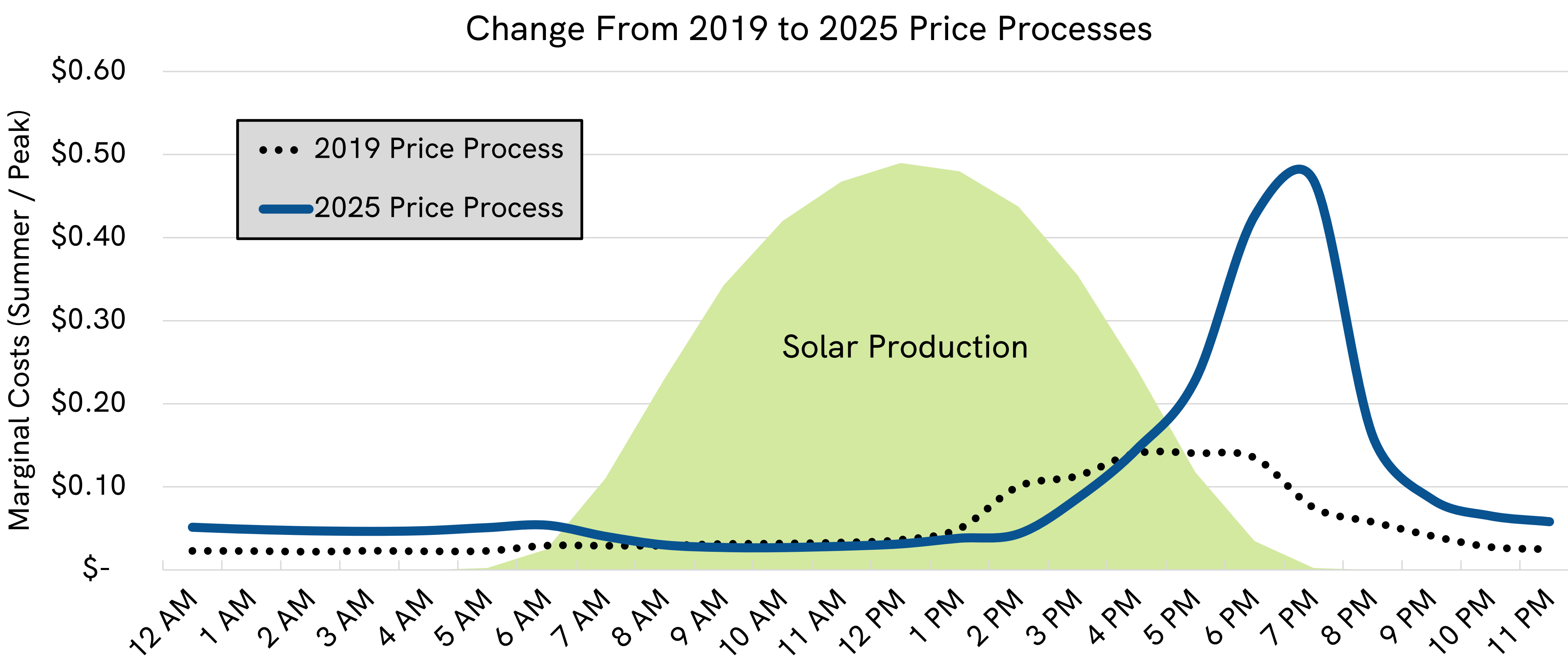
Recent Price Changes



Improved Equity in Recovery of Cost to Serve by Class

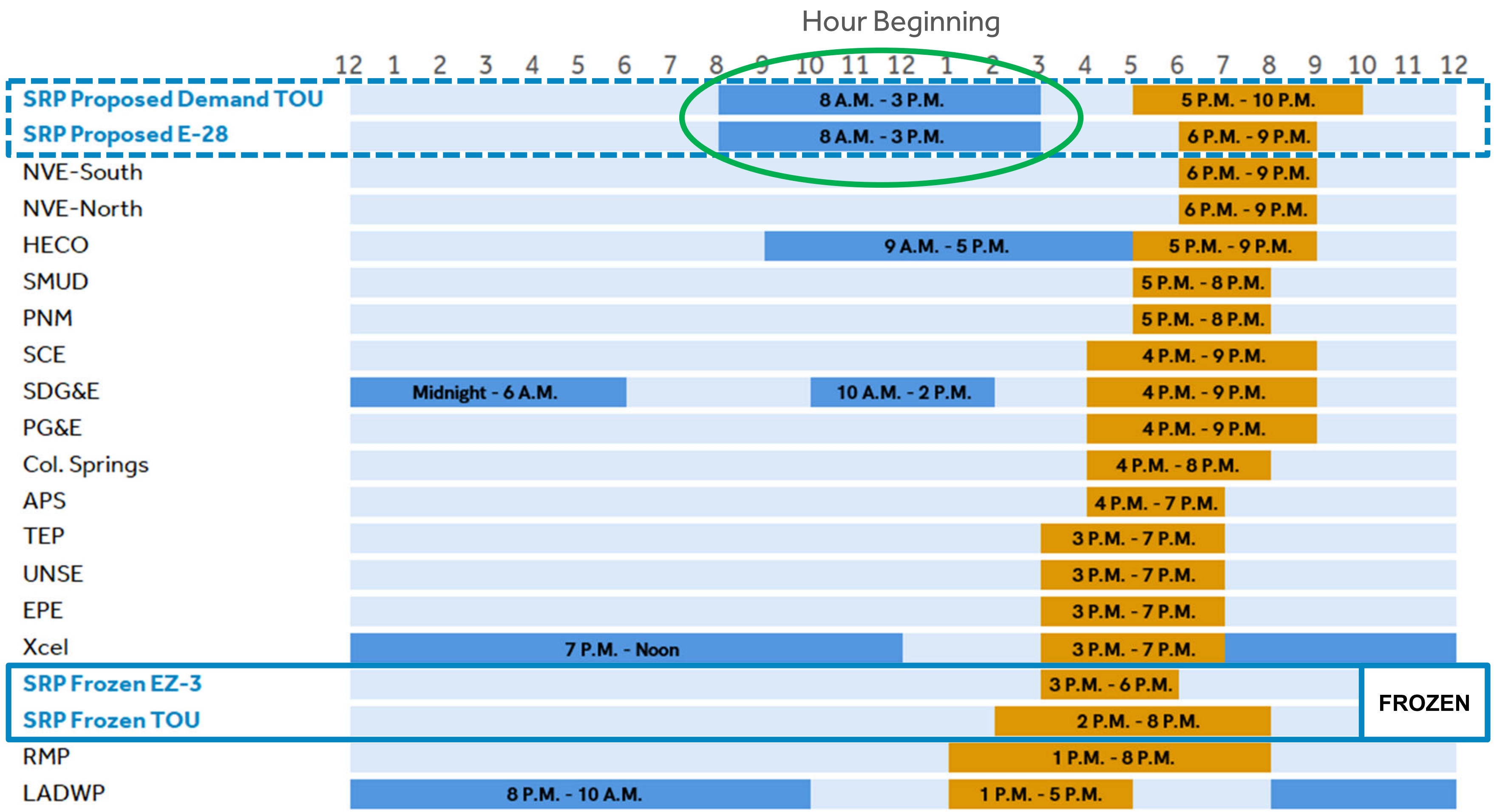


High-Cost Period Shifting Later in the Day



Time-Of-Use (TOU) Hours

On Peak
Off Peak
Super Off Peak



Proposed Changes in TOU Hours

- New and updated TOU plans for Residential, General Service, and Large General Service
  - Higher system costs are shifting to later in the evening and the lower-cost hours are shifting to early- and mid-day periods
- Freeze and sunset the suite of legacy TOU price plans
  - Customers currently on a legacy price plan can stay on that frozen plan until eliminated (by November 2029)
- TOU-differentiated Fuel and Purchased Power Adjustment Mechanism (FPPAM)
  - Time-differentiated prices in the adjustment mechanism more closely aligns revenue collection with costs

Extremely Large-Load Customers – Risks

- Extremely large-load customers will require SRP to make significant investments in generation and transmission assets
- Unless appropriate adjustments are made, there's a risk of SRP's current customers paying for these assets through increased rates due to:
  - Generation capacity and energy investments
  - Customer load not materializing as forecasted
  - Load materializing to recover costs, but later decreasing due to increased technology efficiencies or reduced demand

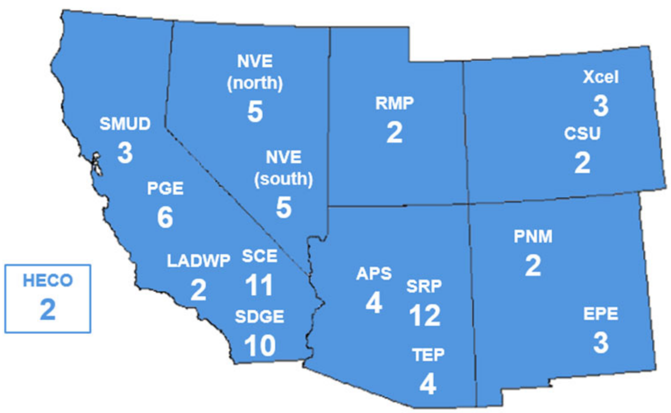
Large Load Customers – Proposed Changes to E-67

- Remove load factor requirement
- Change demand from max kW to max on-peak kW
  - Encourages on-peak load shifting from customers with that capability
- Minimum bill applicability to protect other customers from additional costs
  - Generally applicable to (a) loads served on or after November 1, 2025, that are forecasted to reach 20 MW or more, and (b) loads that reach 20 MW or more after November 1, 2025
  - Monthly minimum demand charge based on forecasted load (80% of forecasted demand)
  - Minimum bill also includes any other applicable fixed monthly charges and any minimum dollar amounts specified within the Agreement for Electric Service
    - May include minimum energy charges

Residential Price Plans

Residential Price Plan Suite Simplification

Residential Rate Count (current)



Price Plan		Current	Proposal
E-13	Customer Generation Export	Active	Frozen
E-14	Customer Generation Export w/ EV	Active	Frozen
E-15	Customer Generation Avg Demand	Active	Frozen
E-16	**SRP Manage Demand 5-10 P.M. and Save**	**n/a**	**New**
E-21	EZ-3 (3-6pm)	Active	Frozen
E-22	EZ-3 (4-7pm)	Active	Frozen
E-23	**Basic**	**Active**	**Active**
E-24	**Prepay (M-Power)**	**Active**	**Active**
E-26	Time-of-Use (2-8pm)	Active	Frozen
E-27	Customer Generation Demand	Active	Frozen
E-27P	Demand Pilot	Pilot	Frozen
E-28	**SRP Conserve 6-9 P.M. and Save**	**Pilot**	**New**
E-29	EV (overnight charging)	Active	Frozen

Equalized Prices

Simplified Residential Price Plan Suite

	Name	Description	Applicability
E-16	Demand Price Plan for Time-of-Use	Manage Demand 5-10 p.m. and Save (daily super off-peak 8 am – 3 pm)	Solar & Non-Solar
E-23	Standard Price Plan	Basic Price Plan	Non-Solar*
E-24	M-Power Pre-Pay	Pre-Pay	Non-Solar
E-28	Time-of-Day Service w/ Super Off-peak	Conserve 6-9 p.m. and Save (daily super off-peak 8 am – 3 pm)	Solar & Non-Solar

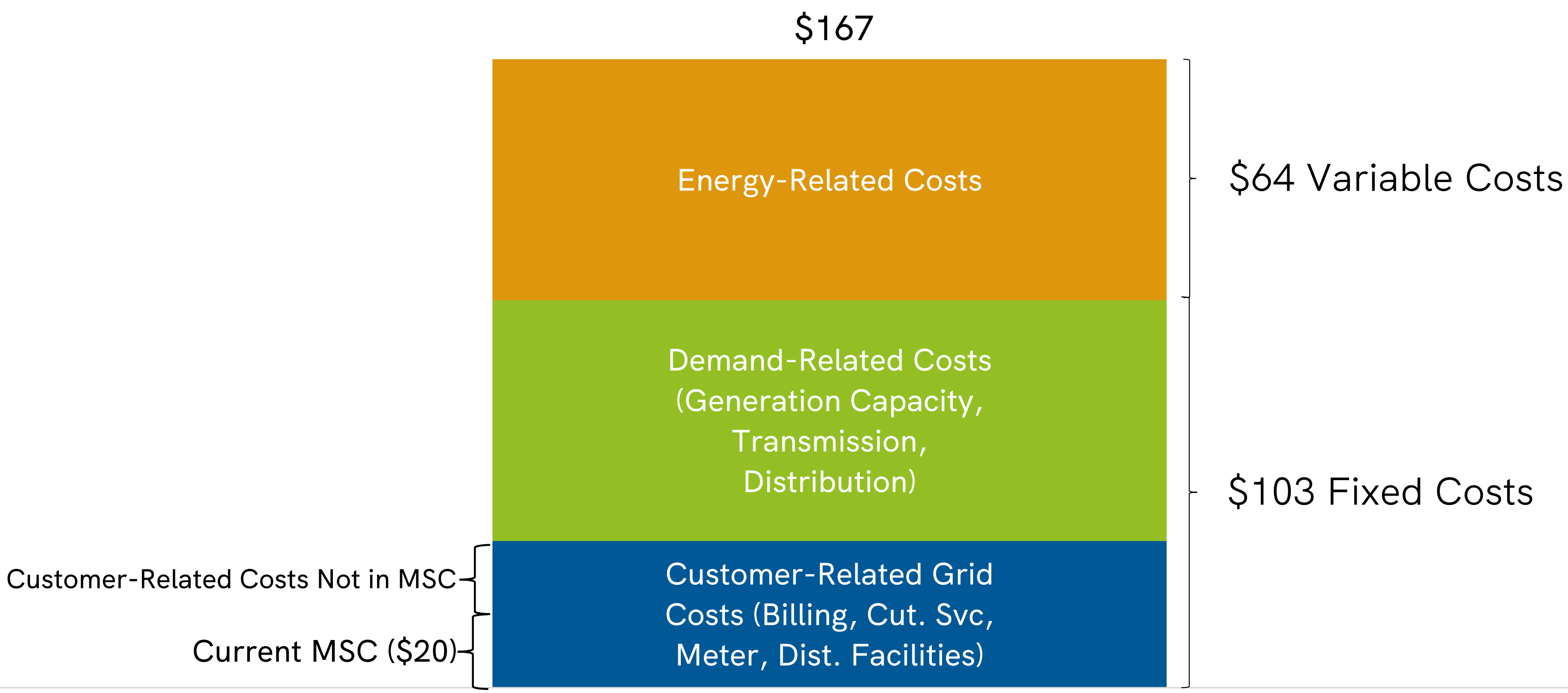
*Certain grandfathered solar customers are eligible for a limited time

Residential Price Plans - Proposal Highlights

Price Plan	Name	Annual Impact (%)	Proposed Status
E-16	Demand Price Plan for Time-of-Use	-	New
E-21	"EZ-3" Super Peak Time-Of-Use 3-6 p.m.	3.7%	Frozen
E-22	"EZ-3" Super Peak Time-Of-Use 4-7 p.m.	2.7%	Frozen
E-23/E-24	Standard / "M-Power" Pre-Pay	3.5%	Active
E-26	Time-Of-Use	2.7%	Frozen
E-28	Time-of-Day Service w/ Super Off-peak	-	New
E-29	Electric Vehicle	2.7%	Frozen
Residential		**3.4%**	**Recovery of Costs: $0.91 per $1**

E-13	Customer Generation Time-Of-Use Export	4.9%	Frozen
E-14	Customer Generation Electric Vehicle Export	3.6%	Frozen
E-15	Customer Generation Average Demand	5.9%	Frozen
E-27	Customer Generation	5.9%	Frozen
Residential Solar		**5.5%**	**Recovery of Costs: $0.76 per $1**

Total Costs Per Month – Average Residential Bill



2025 Cost Allocation Study | FP25 FY26| Avg. Residential Bill

Monthly Service Charge Tiers - Applicability

TIER 1

28% of residential customers

TIER 2

69% of residential customers

TIER 3

3% of residential customers

MSC	$20	$30	$40
Average Customer Grid Cost	$35	$39	$49
Applicability	Single unit in a multi-family house, apartment unit, condominium unit, townhouse, or patio home with service of 0-225 amps	Dwellings not in tier 1 with service of 0-225 amps	Any residence with service of more than 225 amps

Monthly Service Charge Tiers – Bill Impacts

TIER 1	TIER 2	TIER 3
		
28% of residential customers	69% of residential customers	3% of residential customers

MSC	$20 (18.4% of bill)	$30 (15.9% of bill)	$40 (11.5% of bill)
Average Bill Before Proposal	$108.99	$179.66	$332.16
Average Bill Change	-$0.35	+$8.77	+$15.37

Economy Price Plan (EPP) Proposal

Increase qualification from 150% Federal Poverty Level to 200%

Increase discount from $23/mo to $25/mo*

Estimated 100,000+ customers newly eligible

Budget increase from $20M (80k + customers) to $41M (estimated 55k new sign ups)

*Management is supportive of evaluating alternative structures

Residential Solar Proposal

1) Same TOU price plans as non-solar customers
    - Continue to offer a demand price plan (new E-16)
2) Same Monthly Service Charge as non-solar customers
3) Export rate: Increased, tied to market = $0.0345 / kWh
    - Open to alternative cost-based approach
4) Planning to develop REC incentive program

General Service Price Plans

General Service Price Plans - Proposal Highlights

Price Plan	Summary of Proposal	Annual Impact (%)

E-32
Time of Use
	• Update prices according to the target revenue changes in the CAS
	• Update Time-of-Use Hours (year-round)
	    • On-Peak: Weekdays 5 p.m. – 10 p.m. (MST)
	    • Off-Peak: Daily 8 a.m. – 3 p.m. (MST)
	    • Shoulder-Peak: All Other Hours
		1.3%

E-33 Experimental Time-of-Use	• Freeze from new participation as of November 2025 billing cycle • Update prices according to the target revenue changes in the CAS	-
E-34 M-Power	• Update prices to align with E-24 (M-Power), but with General Service fuel prices	-
E-36 Standard	• Update prices according to the target revenue changes in the CAS	1.3%
Total General Service		**1.3%**

Pumping and Lighting Price Plans

Pumping & Lighting Price Plans - Proposal Highlights

Price Plan	Summary of Proposal	Annual Impact (%)
E-47: Standard	• Update prices according to the target revenue changes in the CAS	1.3%
E-48: Time-of-Use	• Update prices according to the target revenue changes in the CAS	1.8%
Total Pumping Service		**1.3%**

E-54: Traffic Signals	• Update prices according to the target revenue changes in the CAS	2.2%
E-56/E-57: Public Street Lights/ Private Security Lighting	• Update prices according to the target revenue changes in the CAS	1.3%
Total Lighting Service		**1.3%**

Large General Service Price Plans

Large General Service Price Plans - Proposal Highlights

Price Plan	Summary of Proposed Changes	Annual Impact (%)

All E-60s	• Update Time-of-Use Hours
	  • On-Peak: Summer: Daily 5 p.m. – 10 p.m. (MST)
	    Winter: Weekdays 5 p.m. - 10 p.m. (MST)
	  • Off-Peak: Year-Round: Daily 8 a.m. – 3 p.m. (MST)
	  • Shoulder-Peak: Year-Round: All Other Hours
		1.3%

E-61 Secondary Large General Service	• Update prices according to the target revenue changes in the CAS • Update Time-of-Use Hours as shown above	1.3%
E-63 Primary Large General Service	• Update prices according to the target revenue changes in the CAS • Update Time-of-Use Hours as shown above	1.3%

Substation Large General Service Price Plans - Proposal Highlights

Price Plan	Summary of Proposed Changes	Annual Impact (%)

Substation Large General Service	• Update Time-of-Use Hours
	  • On-Peak: Summer: Daily 5 p.m. – 10 p.m. (MST)
	    Winter: Weekdays 5 p.m. - 10 p.m. (MST)
	  • Off-Peak: Year-Round: Daily 8 a.m. – 3 p.m. (MST)
	  • Shoulder-Peak: Year-Round: All Other Hours
	• 20.1% reduction to transmission component price for customers receiving service at voltages above 69kV
		1.3%

E-65: Substation Large General Service	• Update prices according to the target revenue changes in the CAS • Update Time-of-Use Hours as shown above	1.3%
E-66: Substation Large General Service (Interruptible)	• Update prices according to the target revenue changes in the CAS • Update Time-of-Use Hours as shown above	1.3%
E-67: Large Load Substation Large General Service	• Update prices according to the target revenue changes in the CAS • Update Time-of-Use Hours as shown above • Eliminate minimum load factor requirement • Change demand from max kW to on-peak max kW • Minimum Billing Demand – Loads at or above 20 MW generally required to pay higher of 80% of forecasted demand or max on-peak demand each month	1.3%

Riders

Rider Proposal Highlights

- **Buyback Rider** and **Renewable Net Metering Rider:** Index change and minor transaction fee update
- **Energy Attribute Certificate Rider**: Make the "Renewable Energy Credit Pilot Rider" permanent and expand it to include other energy attribute certificates
- **Carbon Reduction Rider (New)**: Allow customers to participate in programs developed by SRP with respect to carbon markets associated with the reduction, removal, avoidance, capture or sequestration of carbon dioxide emissions.
- **Standby Rider:** Updated consistent with changes in E-60 price plan pricing changes

Riders to be eliminated:

(no participating customers)

Active	Frozen
Market Price (Pilot)	Business Community Solar (Pilot)
Renewable Energy Services (Pilot)	Community Solar for Schools (Pilot)
Sustainable Energy Services (Pilot)	Energy for Education (Pilot)
Use Fee Interruptible	Residential Community Solar (Pilot)

2025 Price Process Objectives

Limited revenue increase	Simplified Residential price plan portfolio	Increase assistance to limited-income customers
Align TOU hours with evolving costs	Address common solar customer concerns	Protections for existing customers from new large load investments

Pricing Process Timeline

thank you!

Delivering water and power™

PFM Report for the Salt River Project Price Process

Financial Market and Capital Structure Considerations In Public Power Pricing Decisions

Michael Mace, Senior Director

January, 2025

PFM

Charlotte, NC

pfm.com

Introduction

- SRP Price Process has historically included a Report on the projected financial impacts of the pricing proposal
  - *Analyzing financial metric, credit rating and investor perception impacts*
- PFM Financial Advisors ("PFM") has delivered the Report for recent pricing processes
  - *PFM serves as financial advisor to over half of the 50 largest public power systems*
  - *Advising on debt issuance and financial policies*
- The PFM Report is focused on the financial impacts of price proposals
  - *Incremental impact on key financial metrics*
  - *Expected bond rating agency reactions to metrics and message*
  - *Investor perception - maintaining SRP's position as a premier credit*

The Value of Credit Strength to Customers

- It is not just about bonds, credit rating agencies and investors
- Credit Strength is important to current and future customers
  - *Access to low-cost capital allows cost-effective funding for critical assets*
  - *Responsible use of borrowing capacity continues the legacy of credit strength*
  - *Current customers benefit greatly from SRP's historic credit strength*
- How do Investors and Rating Agencies evaluate credit strength?
  - *Comparison of Quantitative Financial Metrics and Rate Competitiveness*
  - *Non-Quantitative Analysis of:*

  Management, Asset Diversification, Rate-Making, Environmental Risk, Customer Concentration…
- Investors deliver the ultimate "Judgment" – interest rates on bonds
  - *Best public power credits (like SRP) can borrow long-term at roughly 4% today*
  - *Challenged credits borrow at rates closer to 5%*
  - *Adding roughly $210 million in interest over the life of $1 Billion debt issue*

The Current Price Process and Proposal

- First Base Price increase in 5 years – CPI up 23% since 2019
- Proposal responds to, and positions for, the changing utility landscape
  - *Projected demand growth exceeds that experienced in several decades*
  - *Requiring an array of new and varied capital projects*
  - *In an environment of considerable uncertainty*
  - *Fortunately, SRP approaches these changes from a position of financial strength*
- Management proposal of 4.0% Base Price increase and 1.6% Fuel and Purchase Power decrease
  - *In keeping with SRP's history of affordable, sub-inflationary pricing adjustments*
  - *Pricing structure recovers and allocates costs in recognition of cost responsibility*
- Proposed Adjustments expected to maintain SRP financial strength, yet with some decline from recent very strong financial metrics

Positioning for the Future – Load Growth and Capital Needs

- Like many major utilities, SRP's capital needs and debt issuance over the next several years are expected to reshape its balance sheet
  - *Current balance sheet - <u>$15.1 billion in assets and $5.5 billion of long-term debt</u>*
  - *6-year capital plan - <u>$12.3 billion, funding roughly half with new debt</u>*
  - *Exactly how much debt will depend on the timing and amount of price adjustments*
  - *Price adjustments create revenue to fund a major portion of new capital*
  - *Price adjustments and debt issuance affect financial metrics, strength and ratings*

- Without Base Price increase and its related revenue, greater reliance on debt is projected to drive debt ratio from 46% to 58% by 2030, which would be the highest SRP debt ratio in 30 years
  - *This degree and speed of debt ratio deterioration would be a material departure from SRP's traditional financial stewardship*

Positioning for the Future – SRP's Financial Metrics

- Public Power Financial Metrics Description:

Debt Ratio(s) or Leverage – the ratio of debt to assets or capitalization. Total Capital is defined as debt + accumulated net revenues, with net revenues as an equity-type metric for governmental utilities. Lower debt ratios indicate lower debt costs, more flexibility and lower risk.

Debt ratio is typically slow to move and a good measure of long-term position and direction

Debt Service Coverage – the ratio of annual cash flow available to pay debt service relative to the amount of the annual debt service payments. Higher coverage creates more capacity to absorb revenue or expense volatility and still be able to meet debt service payments.

Liquidity – the amount of cash, investments, and short-term borrowing capacity relative to the amount of ongoing operating expenses. Greater liquidity is another metric which indicates better ability to respond to cash flow volatility.

SRP Debt Ratio and Ratings Compared to Public Power Peers

Public Power Peer Group Utility		Net Position	Long Term Debt	Total Capital	Debt Ratio	Credit Ratings
Salt River Project	SRP	6,408	5,471	11,879	**46.1%**	**Aa1/AA+/--**
Colorado Springs Utility	CSU	2,526	2,412	4,938	**48.8%**	**Aa2/AA+/--**
JEA (Jacksonville, FL)	JEA	1,484	1,426	2,910	**49.0%**	**A1/A+/AA**
Orlando Utility Commission	OUC	1,695	1,726	3,421	**50.5%**	**--/AA/AA**
Sacramento Muni Utility Dist	SMUD	2,587	2,921	5,508	**53.0%**	**Aa2/AA/AA**
Austin Energy	AE	1,766	2,021	3,787	**53.4%**	**Aa3/AA-/AA-**
San Antonio City Public Service	SACPS	4,364	7,175	11,539	**62.2%**	**Aa2/AA-/AA-**
LA Dept Water & Power (Power)	LADWP	7,027	12,118	19,145	**63.3%**	**Aa2/A/--**
Omaha Public Power District	OPPD	1,544	3,205	4,749	**67.5%**	**Aa2/AA/--**
Long Island Power Authority	LIPA	827	9,292	10,119	**91.8%**	**A2/A/A+**

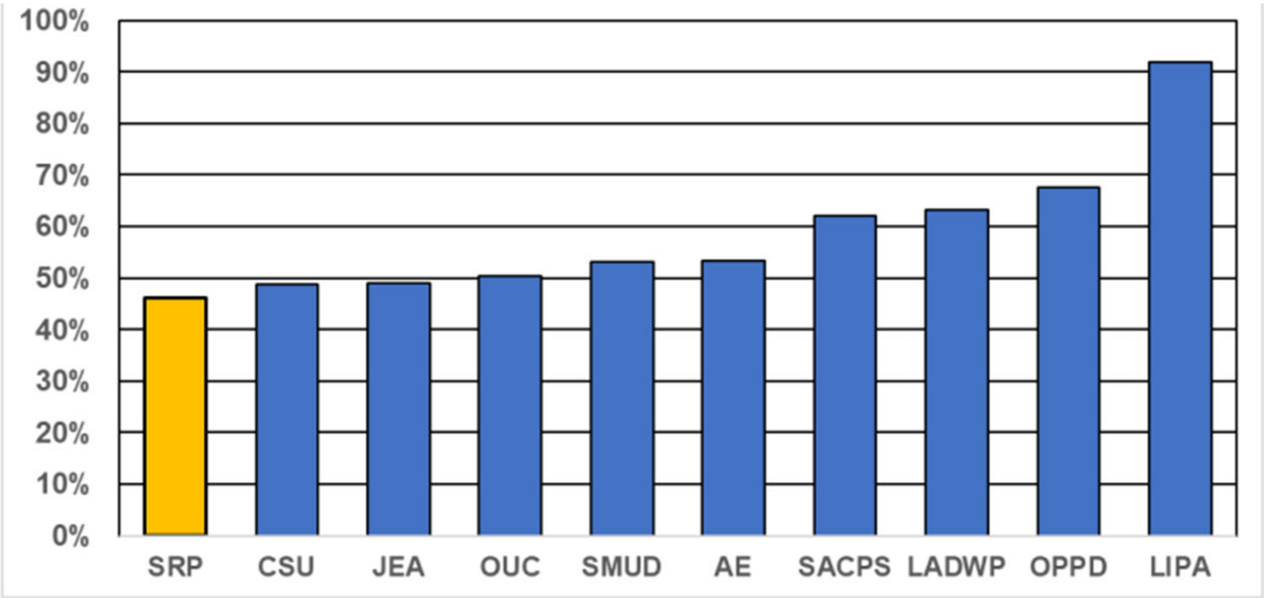
Source: debt to capitalization ratio calculated from most recently available audited financial statements
Reflects recent LADWP downgrade

Credit Ratings

AAA	Strongest, risk-free
AA	Very strong, minimal risk
A	Solid credits, some concerns
BBB	OK credits, material risks
BB & lower	Risk of repayment

- Takeaways: *Most large public power utilities are very strong credits*
  SRP clearly one of the strongest credits
  Financial strength is often the product of decades of policy and focus

SRP Current Debt Ratio Compared to Public Power Peers



Source: debt to capitalization ratio calculated from most recently available audited financial statements

- Takeaways: *Most large public power utilities are very strong credits*

  SRP clearly one of the strongest credits

  Financial strength is often the product of decades of policy and focus

SRP's Financial Projections Without Base Price Increase

FP26 Case: No Base Price Increase in FY26 or FY28, 1.6% FPPAM Decrease in FY26							($ Millions)
Fiscal Year end April 30	2025	2026	2027	2028	2029	2030	6 Yr Total
Combined Net Revenues	461	264	178	44	241	491	1,679
Funds Avail for Corp Purposes	923	839	814	716	826	1,067	5,185
Capital Expenditures	1,694	1,507	1,733	2,050	2,578	2,750	12,313
Debt Issuance	789	672	1,137	1,437	1,841	1,794	7,670
Debt Ratio	46.6%	47.4%	49.8%	53.2%	56.4%	58.1%	
Debt Service Coverage	3.95 X	3.63 X	3.32 X	2.89 X	2.92 X	3.09 X	

Projections provided by SRP

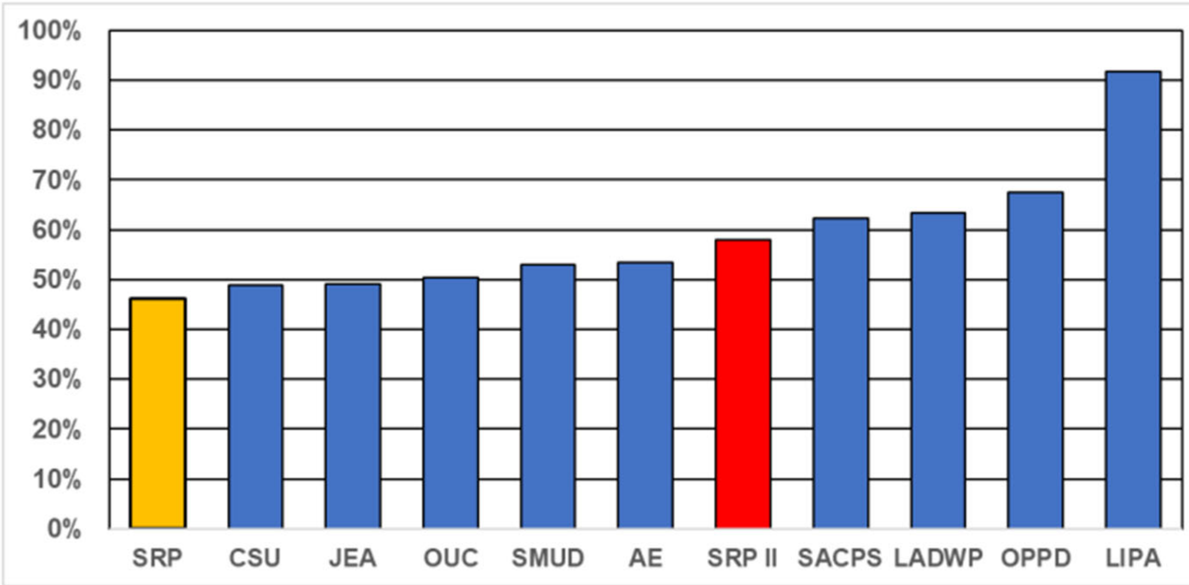
- Key Metrics:

Debt Ratio increase from 46.6% to 58.1% (was 41.7% in 2022)
Requires ~$7.7 Bn new debt to fund capital needs
DS Coverage declines from ~4.0X to below 3.0X

SRP Potential Debt Ratio Compared to Public Power Peers

- SRP Projected Debt Ratio in 2030 (“SRP II”) w/o Base Price Increase

Hypothetical “SRP II” Debt Ratio compared to current Peer Group Debt Ratios



SRP debt ratio would move from leader to middle of the pack

Still likely a solid credit, but going in the wrong direction

Positioning for the Future – SRP's Financial Projections

- The No Increase scenario generates ~$4.6 Bn over 6 years to fund a portion of the ~$12.3 Bn capital program
  - *But requires ~$7.7 Bn of new debt to fund the remainder*
  - *Projected Debt Ratio would increase to 58.1%*
  - *Debt Service Coverage declines by roughly 30% from current level*
- While the resulting financial metrics of No Increase are not "troubling", the financial deterioration and departure from historical practices are likely to trigger rating agency concerns and rating downgrades
- SRP needs a Base Price increase to preserve its position as the premier public power credit and preserve its competitive borrowing cost advantage

Positioning for the Future – SRP's Financial Projections

- The Proposed Adjustments are projected to preserve SRP's debt ratio at roughly 50% until 2028
  - *Debt Service Coverage projected to remain close to the 4.0X level*
- PFM expects these metrics, barring other unforeseen changes, to allow SRP to retain its current credit ratings for 3-5 years
- The Proposed Adjustments balance the goal of preserving fair and reasonable prices, with that of preserving financial strength required for low-cost capital and continued cost competitiveness
- PFM supports the Proposed Adjustments as financially prudent

Confidential

On-Site Solar Rate Trends

Salt River Project Board Presentation

January 31, 2025

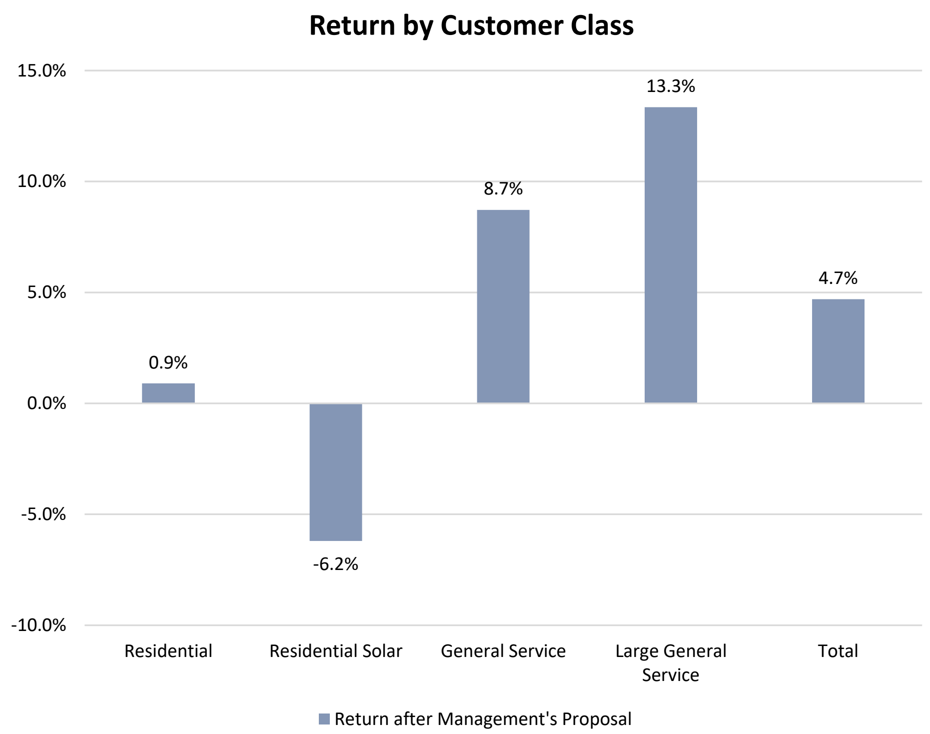
Topics

1. Review of Residential Customer Generation Price Plan Returns
2. Lifetime Cost of Generation by Type
3. State Actions to Address Rooftop Solar Cost Shifting
4. California Case Study
5. Conclusions

1. Residential Customer Generation Price Plan

Under Collection of Allocated Costs

- The proposed return for Residential Solar customers is -6.2%.
- A negative return indicates that the class revenues are not sufficient to cover the total costs to serve that class.
- Any under recovery by one class impacts other classes who must make-up the difference.
- Competing rate design principles limit how quickly SRP can address inter-class cost shifting. Managements proposal, including simplifying plans to one set of time-of-use rates, helps address some of these issues.



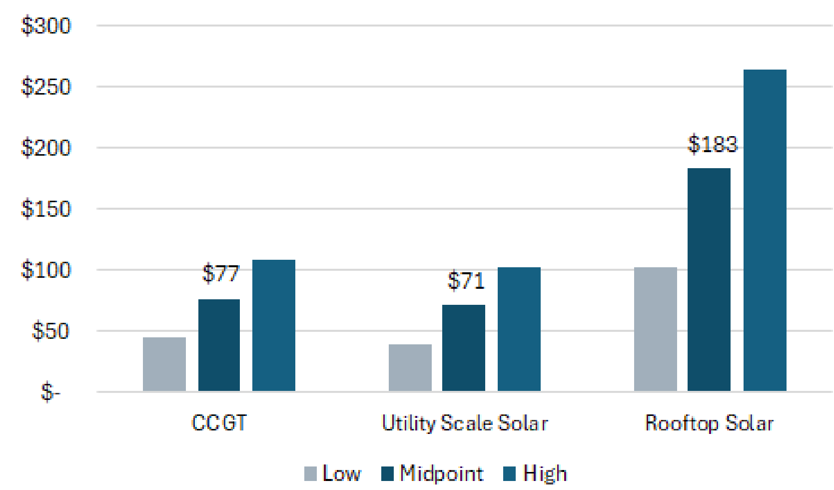
Source: Proposed Adjustments to SRP's Standard Electric Price Plans Effective With the November 2025 Billing Cycle (Amended and Restated)

2. Cost of Generation by Type

Lifetime Cost of Generation

- The lifetime cost of operating various types of generation can be captured through a Levelized Cost of Energy (LCOE) analysis which allows for a general comparison across generation options.
- The LCOE is best considered as a range of costs given a number of factors (e.g., federal incentives, “firming” costs, location, gas prices and value of renewable energy certificates)
- This LCOE analysis shows that a gas fired combustion turbine (CCGT) and utility scale solar have similar midpoint costs of $77/MWh and $71/MWh, respectively.
- By contrast, rooftop solar generation costs are far higher with a midpoint cost of $183/MWh.
- Thus, utility scale solar backed by fossil generation and/or storage can be a cost-effective resource for entities considering solar.

LCOE Adjusted for Firming and Federal Incentives ($/MWh)



Source: Lazard Levelized Cost of Energy Comparison Version 17.0, 2024.

3. State Actions to Address the Rooftop Solar Cost Shift

Background

- Rooftop solar cost shifting from solar customers to non-solar customers has become a significant concern among regulators.
- Recognizing the potential negative impacts of cost shifting, the National Association of Utility Regulators (NARUC) has stated in its Distributed Energy Rate Manual[1] that:

> *In sum, under the traditional ratemaking model and commonly used rate design, if the utility passes its relevant threshold of DER adoption, the utility may face significant intra-class cost shifting and erosion of revenue in the short run. If left unaddressed, the utility could face pressures in the long term that might prevent it from recovering its sunk costs, which are necessary to provide adequate service.*

Policy Changes

- Legislators and regulators have acted by:
  1. Reforming net metering to ensuring that roof top solar customers pay a fair portion of fixed costs when they rely on the utility system.
  2. Aligning compensation for power sent back to the grid to be more reflective of wholesale power costs.

1. See 2016 NARUC Distributed Energy Resources Rate Design and Compensation Manual at 67.

3. State Actions to Address the Rooftop Solar Cost Shift (Cont.)

Selected State Actions Applicable to Investor-Owned Utilities

- Many states have taken actions to reduce NEM credits by reducing or eliminating the timeframe over which netting may occur as listed below:
  - **Arizona:** Transitioned to net billing and mandatory time-of-use rates, where production and consumption are netted at a sub-monthly interval.
  - **California:** Eliminated NEM and replaced it with net billing for new solar customers. Mandatory time-of-use rates for solar customers and reduced compensation rates for excess generation.
  - **Hawaii:** Implemented a net billing tariff with varying credit rates for excess generation.
  - **Indiana:** Adopted net billing as a replacement to traditional NEM.
  - **Louisiana:** Shifted to net billing with specific compensation rules.
  - **Michigan:** Introduced net billing to replace traditional NEM.
  - **Mississippi:** Adopted net billing with instantaneous netting.
  - **New York:** Net billing for larger commercial customers and community solar projects, while retaining NEM for residential and small commercial customers.
  - **South Carolina:** Mandatory time-of-use rates for residential solar customers with monthly netting by time-of-use period and a minimum bill.
  - **Texas:** No NEM provisions. Retail electric providers may offer an export rate.
  - **Utah:** Implemented net billing with a varying rates for excess generation.

Source https://www.dsireinsight.com/blog/2021/5/25/status-of-state-net-metering-reforms

4. California Case Study

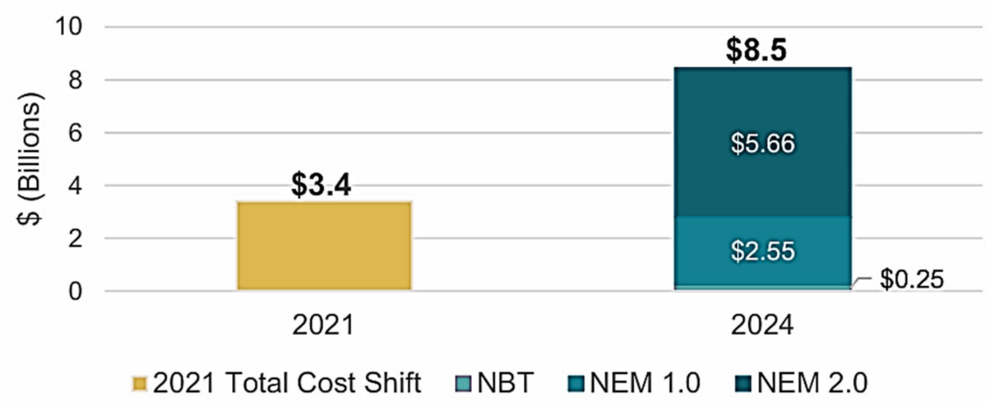
Background

- California has by far the most rooftop solar capacity of any state, given prior incentives and high electric rates.
- The growth in rooftop solar has caused a significant shift of utility costs to non-solar customers, which the state has been trying to remedy with various reforms to its NEM tariff.

2023 – NEM 3.0

- With the annual cost shift rising to $3.4 billion in 2021, the CPUC initiated further revisions to state NEM policy under NEM 3.0 which further reduced roof-top solar compensation by 75% yet retains compensation for legacy customers.

California Rooftop Solar Cost Shifting, 2021 and 2024



Source: 2024 Net Energy Metering Cost Fact Sheet available at: https://www.publicdvocates.cpuc.ca.gov/press-room/reports-and-analyses/nem-cost-shift-methodology-fact-sheet-2024

2024 – Governor's Executive Order

- The state of California found that NEM policies were shifting an estimated $8.5 billion to non-solar customers in 2024, which equals approximately $795/yr. per customer across the 10.6 million non-solar customers within the three CA IOUs.
- Governor Newsom responded by issuing an Executive Order in October of 2024 directing the CPUC to address the cost shift caused by the legacy NEM programs.

5. Conclusions

Cost Allocation

- Solar customers should be responsible for all of their costs of service regardless of NEM structure.
- Inter-class subsidization occurs when customers do not fully contribute their allocated cost of service.

Cost of Generation by Type

- Utility scale solar can be cost competitive with combined cycle generation, even when considering system firming costs.
- Rooftop solar costs are far higher than utility scale solar and may not be the most effective route to achieve widespread solar generation growth.

State Actions

- States have increasingly been taking action to address inter-class cost shifting from NEM policies and widespread rooftop solar proliferation.
- Transitioning from net metering to net billing has occurred in many states.
- Grandfathering of legacy policies can have long-lasting impacts to interclass equity.

[redacted]

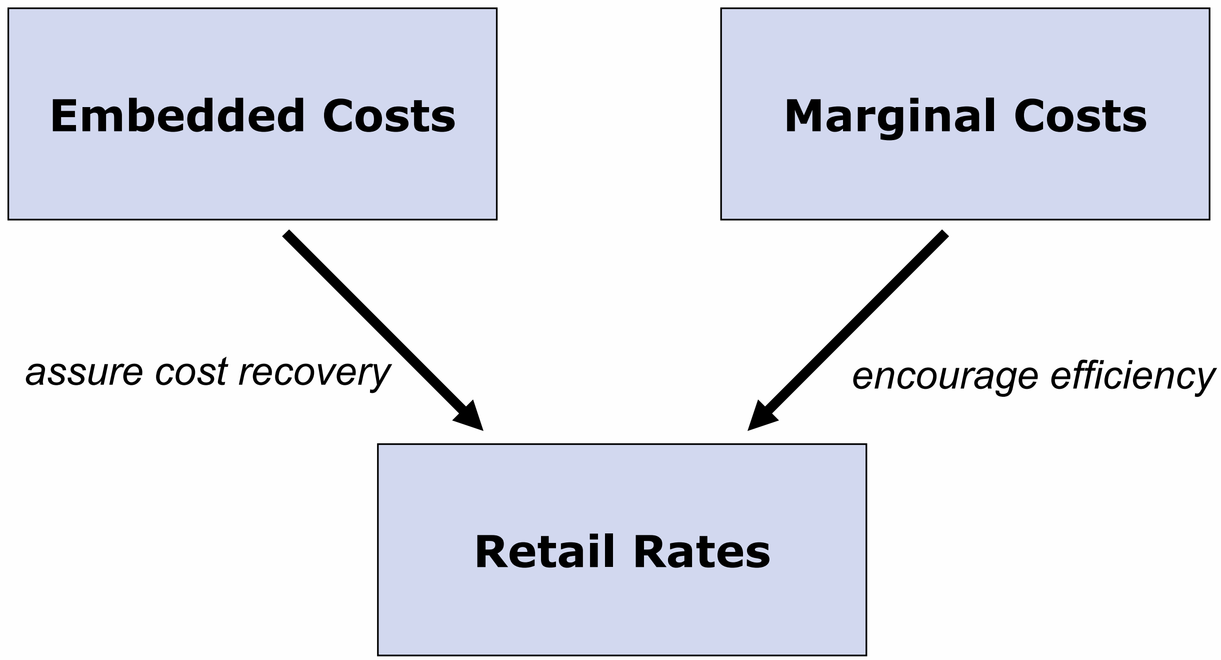
Salt River Project Price Process: Review of Management Proposal

Bruce Chapman

Analysis Team: Daniel Hansen, Michael Clark

January 31, 2025

Costs Underlie Rates



Agenda

- Cost allocation study
- Marginal cost study
- Rate design proposals
- Summary of findings

- Appendix: rate class detail

Cost Allocation Study (CAS)

Purpose, Steps, and Results of the CAS

- Purpose:
  - fully allocate financial costs to rate classes
- Steps:
  - Functionalize: share costs among functions (generation, transmission, distribution, etc.)
  - Classify: share costs in each function by cost causative factor (customer-, demand-, energy-driven)
  - Allocate: share costs in each causative group across rate classes
- Results:
  - Total costs allocated by rate class
  - Comparison of revenues to costs by class (the “revenue/cost ratio”)

CAS Methodology Changes

- Purpose: to keep methods of cost allocation in line with theory, industry standards, and data availability
- FPPAM Cost Classification:
  - Reason for change: increased share of fuel and purchased power costs based on peak demand
  - Change: classify costs as partly demand-driven instead of entirely energy-driven
- Distribution Cost Classification:
  - Reason for change: new operation & maintenance cost data available
  - Change: improve classification sharing between customer- and demand-driven causation
- Demand-Related Generation Cost Allocation:
  - Reason for change: demand-related costs are now better reflected by proximity to net peak, as measured by loss of load probability (LOLP), than by previous (coincident peak) allocator
  - Change: convert to LOLP allocator for generation and FPPAM demand-related cost allocation

Our Assessment of CAS

- Methodology reflects industry practice and theory
- Management's proposed modifications to methodology respond to changing circumstances and are consistent with industry practice
- Management's customer cost "smoothing" calculations appear in the CAS but are part of rate design
  - This is a matter of convenience and not a methodology issue
  - Rate of return by class is properly based on allocated costs prior to smoothing

Marginal Cost Study (MCS)

Purpose, Types of MC, and Results of the MCS

- Purpose:
  - Understand and measure how costs change as customer behavior changes
    - Behavior change is measured via changes in number of customers, level of peak demand, and overall consumption
- Types of Marginal Cost:
  - Marginal energy costs: wholesale market prices (history and forecast)
  - Marginal demand costs:
    - Generation: market estimates of value of capacity
    - Transmission & Distribution: estimates of investment cost necessary to meet demand growth
  - Marginal customer costs: historical data on customer service, metering, billing costs
- Results:
  - Marginal Cost estimates for decision-making, e.g.:
    - Guide for energy price setting, subject to revenue sufficiency
    - Determining appropriate Time-of-Use periods and price

Our Assessment of MCS

- Management's methodologies for calculating the various types of marginal cost adhere to industry practice and theory
- Computations make use of appropriate contemporary information from markets and from internal records

Rate Design Proposals

SRP's Pricing Principles

- Sufficiency – recover sufficient revenues
- Cost Relation – reflect cost of service (from the CAS)
- Equity – be perceptibly fair
- Choice – offer diverse customers rates that meet their needs
- Gradualism – avoid rate changes that rapidly change bills significantly

Criteria of a Successful Rate Design (Bonbright Principles)

- Revenue-related
  - Recover costs fully
  - Stable rate design
  - Stable revenues
- Cost-related
  - Encourage efficient use of energy
  - Reflect marginal cost
  - Avoid undue discrimination
  - Perceptibly fair
- Practical
  - Simple, acceptable to all parties
  - Free from controversy
- Problem: trade-offs are necessary

Rate Structure and Pricing Modifications

- Time-of-Use (TOU) Pricing Periods
  - Most of SRP's rates have energy and demand charges that vary by season and time of day
  - Reason for change: marginal cost patterns have changed significantly due to arrival of solar energy. Low costs occur in midday, high costs in the early evening
  - Change: modified boundaries of pricing periods and price levels to conform to new market pricing patterns

Rate Structure and Pricing Modifications (2)

- Customer Charge Levels
  - SRP's customer charges have traditionally been below customer-related unit cost
    - Especially true of residential customers
  - Reason for change: rise of customer diversity and to better align price with underlying costs, and to increase use of fixed charges to recover fixed costs
  - Change: move customer charge upward at a more rapid rate than other charges to reduce the gap between unit cost and customer charge

Our Assessment of Rate Structure Changes

- Management's proposed changes to TOU periods appropriately reflect changes in generation wholesale market cost time patterns
- Management's proposed changes to customer charge levels improve the match between customer bills and cost to serve and reduce the risk of cross subsidy
- Management computed bill impacts by rate class and stratum, revealing that most bill impacts are moderate
  - Large increases often reflect reductions in cross subsidy
  - Bill impacts reflect application of principle of gradualism; price changes move in the direction of changes in costs
- Price changes largely move prices in the direction of price efficiency, i.e., closer to marginal cost

Summary of Findings

Our Assessment of Management's Proposals

- Financial costs are appropriately allocated to rate class
  - Methodology changes respond to changing circumstances
- Marginal costs are appropriately estimated and provide guidance in decision making
- Rates reflect and fully recover costs
- Changes in rate structure reflect changes in time pattern of generation services costs
- Increase in customer charges improves match between fixed charges and fixed costs
- Changes reduce revenue/cost ratio differences across classes

[redacted]

January 23, 2025

Salt River Project
1500 N. Mill Avenue
Tempe, AZ 85288

Dear SRP Board of Directors:

I. Introduction

On December 2, 2024, SRP Management ("Management") announced that it would be opening a public Pricing Process that seeks an overall 2.4% price increase and includes several other adjustments.[1] Concurrent with that announcement, SRP provided public documents describing Management's pricing proposals in the "Proposed Adjustments to SRP's Standing Electric Price Plans Effective with the November 2025 Billing Cycle"[2] ("Proposed Adjustments") and supporting documentation. At the upcoming Board Meeting on January 31, 2025, the SRP Board ("Board") will be receiving a presentation from Management to kick-off a Pricing Process. While WRA has recommendations for improvement on Management's Proposed Adjustments, in considering the publicly available data that has been released, WRA believes that Management's proposal takes many steps in the right direction by focusing on a number of important issues and by updating SRP's tariffs in some innovative ways.

WRA would like to highlight and recognize the efforts of Management in developing this proposal. Specifically, several of SRP's proposed revisions for time-of-use ("TOU") pricing are creative and forward-thinking improvements over existing tariff structures. The proposed new TOU rates align customer incentives and system benefits to best utilize energy resources on a modernizing grid, including by reducing costly curtailment of renewable energy. WRA also applauds Management's

[1] Schuricht, *SRP Initiates Pricing Process that Seeks Price Increase and New Price Plan Options*, SRP (Dec. 2, 2024), https://www.srpnet.com/assets/srpnet/pdf/price-plans/2024/2024%20Price%20Process%20Opens%20News%20Release%20FINAL.pdf.

[2] *Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle,* https://www.srpnet.com/assets/srpnet/pdf/price-plans/2024/Proposed%20Adjustments%20to%20SRP's%20Standard%20Price%20Plans%20Effective%20with%20the%20November%202025%20Billing%20Cycle_Web.pdf.

launch of an Advanced Distribution Management System for managing and controlling demand side resources.[3] While WRA cautions against extending the life of older and uneconomic fossil fueled generation, Management's decisions to invest in upgrading combined cycle plants to increase efficiency and reduce emissions by reducing required minimum runtimes and allowing for more flexible operations of these plants may be beneficial for the system.[4] The issuance of new bonds to refinance debt and drive down customer borrowing costs[5] is a win for customers as well. These are just a few of the highlights in Management's proposal.

As mentioned above, WRA has several recommendations to improve upon existing proposals by Management. These recommendations include:

1. **WRA recommends that rather than moving EZ-3 customers into the E-23 plan, these EZ-3 customers should be moved into the E-28 plan, which is also a TOU plan.**

2. **WRA recommends that Management increase the price differentiation between on-peak and off-peak rates, which could better help incentivize optimal behaviors for those who do not have the option to charge electric vehicles ("EVs") during the day.**

3. **WRA recommends that SRP also develop managed charging programs in the future which can dynamically adjust EV charging in response to actual grid conditions.**

4. **WRA Recommends that SRP build upon the existing Price Principles in place by adding Sustainability to guide future pricing processes.**

5. **WRA recommends that the Board require Management to provide greater detail about SRP's possible use of ZECs and any other energy attribute rider.**

6. **WRA respectfully requests that the Board avoid the risk of using customers funds dedicated to decarbonizing programs that will fail to impact SRP's emissions in a meaningful way by rejecting the proposed Carbon Reduction Rider.**

7. **WRA recommends that the Board advise Management to explore and propose alternative cost allocation methods in its next Pricing Process to address the risks of transferring the costs of Data Center Growth to Residential Customers.**

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[3] *Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle* at 21.
[4] *Id*. at 19.
[5] *Id*. at 24-26.

II. SRP's Time of Use Proposals

A primary feature of SRP's Proposed Adjustments which WRA supports is the prominence of TOU rates. The proposed new TOU tariffs are well designed to support operational efficiency, cost savings, and emission reductions. WRA is encouraged by SRP's approach to its new TOU rates, and the E-28 tariff in particular.

TOU rates are tariffs which charge different amounts for electricity, usually defined by a per kilowatt-hour ("kWh") price, during different periods of the day.[6] These rates have traditionally been used to send price signals to consumers to discourage consumption during peak hours and can also be used to encourage them to consume during periods of lower demand.[7] However, as the grid evolves to include renewable generation, TOU rates should be updated to avoid a contradiction in pricing and system benefits. Academic literature on TOU rates that focuses only on setting prices higher during times of peak demand, and lower during times of lower demand, is becoming outdated, especially if an assumption is made that lower prices and load shifting should focus on increasing usage only during night-time hours. TOU tariffs can be designed to also cut solar curtailment, reducing system emissions and costs for utilities like SRP that have an enormous solar energy resource in their territory. SRP has recognized this and incorporates these principles into many of its TOU rates.

SRP's proposed TOU rates are innovative and align customer financial incentives with what is best for both SRP and other SRP customers.

1. Benefits of TOU Rates

The price signals created by TOU rates impact customer behavior in a way that provides benefits to the electricity grid, participating customers (those enrolled in the TOU rate), and non-participating customers (those not enrolled in the TOU rate).[8] TOU rates help the utility by shifting load away from peak demand periods to times of lower demand, thereby allowing for more efficient operation of the grid.[9] This reduces the need for additional future utility investments in transmission,

[6] Fields, *What are Time-of-Use (TOU) Rates? How do They Work?*, ENERGYSAGE (Dec. 6, 2023), https://www.energysage.com/electricity/understanding-time-of-use-rates/.
[7] *Id.*
[8] *Time-of-Use Rates: Encouraging Residential Customers to Make the Switch*, QUESTLINE DIGITAL, https://www.questline.com/blog/time-of-use-rates-explain-benefits-to-customers/.
[9] Sowder, *What are Time-of-Use Rates? A Guide to TOU for Electric Vehicle Owners*, QMERIT, https://qmerit.com/blog/what-are-time-of-use-rates-a-guide-to-tou-for-electric-vehicle-owners/.

distribution, and generation upgrades to meet higher peak demands, while also minimizing solar curtailment and carbon dioxide emissions, as well as enabling the utilization of low-cost market imports.

To better align TOU tariffs with changes in energy resources and costs at different hours of the day, it is important to both use peak pricing to discourage consumption during certain hours and to set lower-priced super off-peak periods to encourage usage during hours that are most beneficial to both customers and SRP. Adding a super off-peak period to TOU rates adds an additional period with significantly lower prices. Historically, this would typically have been an overnight super off-peak time, but utilities like SRP have come to realize that the cheapest hours are actually daytime hours. Setting a low rate to encourage consumption during those super off-peak hours sends a price signal to customers that those are beneficial periods to use energy.

For SRP, the super off-peak periods are beneficial daytime hours, largely due to the significant increase in the amount of solar on SRP's system. Absent such a price signal in a TOU tariff, solar energy is curtailed during the daytime when solar generation exceeds demand. Curtailment is inefficient—it represents a loss of not only valuable energy on the system, but also the potential for emissions reductions. Solar curtailment can also carry an additional cost, if the utility is contractually obligated to compensate for lost tax credits. Therefore, reducing solar curtailment through a correctly defined TOU rate structure reduces lost energy, while providing cost savings and emissions reductions.

With the proliferation of renewable energy resources on the grid, shifting super off-peak times to the middle of the day helps to drive down costs for customers and further enables additional development of low-cost, low-emissions solar,[10] with less risk of curtailment. Participating customers may also see a reduction in their bill if they're able to take advantage of lower cost hours for consumption, particularly for larger appliances like pool pumps, EV charging, air-conditioning, and other large energy devices in their homes or places of business.[11]

SRP's Proposed Adjustments include several changes for TOU rates. It proposes adding new TOU rates and retiring some existing rates. The new TOU rates include a daytime super off-peak period, and later evening peaks, which maximize benefits. These TOU rates span multiple customer classes and drive usage patterns in a way that is innovative and forward thinking. These TOU rates not

[10] *Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle* at 34.
[11] *Understanding Time of Use (TOU) Rates: What You Need to Know*, FRANKLINWH (March 25, 2024), https://www.franklinwh.com/blog/understanding-time-of-use-rates.

only provide benefits to customers and attempt to maximize grid operation, but they also incentivize growth on both the supply and demand sides, in line with SRP's carbon emissions reduction goals.[12]

SRP has a number of existing TOU rates and recently performed a pilot for a new TOU rate, E-28, which the company is marketing to residential customers as the "SRP Daytime Saver" tariff.[13] The E-28 rate is an improvement over SRP's existing residential TOU rates because it aligns financial incentives for customers that maximize benefits to the grid and other SRP customers. This rate provides daytime super off-peak hours and later evening peak hours, driving usage to times of day when both costs are lower. Also, as solar continues to be added to the grid, it aligns price signals with times that solar is generating at, or near, its peak. In comparison to the existing E-23 tariff, which is available for residential customers, the E-28 TOU rate includes daytime super off-peak pricing, and later evening peak pricing, while the E-23 Basic Price Plan has a uniform price that is charged regardless of the time of day that electricity is used. This non-TOU E-23 plan fails to send price signals to customers that would amplify the benefits from TOU rates.

The proposed E-28 tariff has a number of beneficial qualities that WRA supports. The super off-peak period aligns with solar production and will help to drive demand during periods with maximum solar generation. This would help to reduce solar curtailment (the equivalent of SRP losing free electricity)[14] and allow SRP to maximize the amount of solar that it is able to add to its system. Under the Management proposal, the retirement of several tariffs (E-13,[15] E-14,[16] E-26,[17] and E-29[18]) will, by November 2029, shift many customers into the E-28 plan, aligning both EV and non-EV users onto rates that are better aligned with system costs and periods of solar production.

2. Converting Existing EZ-3 Customers to the E-28 Plan, not the E-23 Plan

Management has proposed freezing several older TOU tariffs and shifting those customers to other rates.[19] The residential E-21[20] and E-22 [21] ("EZ-3") plans will be closed to new customers. The

[12] *SRP 2035 Sustainability Goals*, https://www.srpnet.com/assets/srpnet/pdf/grid-water-management/sustainability-environment/SRP_2035_Sustainability_Goals_Single_Page.pdf.
[13] *Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle* at 94.
[14] *Solar Curtailment*, GRIDX (Oct. 17, 2024), https://www.gridx.ai/knowledge/solar-curtailment.
[15] *Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle* at 48.
[16] *Id*. at 52.
[17] *Id*. at 78.
[18] *Id*. at 94.
[19] *Id*. at 46-47.
[20] *Id*. at 64.
[21] *Id*. at 68.

proposal is to eventually move the EZ-3 customers (no later than November 2029) onto the E-23 Basic Price Plan.[22] However, that means moving customers from a TOU rate to a non-TOU plan. WRA recommends that rather than moving EZ-3 customers into the E-23 plan, these EZ-3 customers should be moved into the E-28 plan, which is also a TOU plan. EZ-3 customers have already opted into a TOU rate and are likely used to having different energy prices during different times of day. While SRP will need to educate any customer moving into a different plan, this task will be easier for customers who are already accustomed to TOU rates.

The E-28 plan, as compared to the E-23 plan, provides a number of benefits, including aligning consumer interests with system benefits, minimizing curtailment, and enabling customers to control their costs, which makes the E-28 tariff superior to the E-23 plan for SRP's participating customers, and even non-participating customers. It would be unwise to miss the opportunity to capture these benefits from a large number of residential customers by moving them by default to a non-TOU plan. SRP should be ensuring that as many customers as possible are engaging with these plans to capture those benefits.

Management's Proposed Adjustments show that 164,007 customers currently use the E-21 plan[23] and 14,912 customers currently use the E-22 plan.[24] This means that there are potentially over 178,000 customers that SRP can transition to its highly beneficial E-28 plan, should those numbers remain stable until these rates are eliminated. This change from E-23 to E-28 appears to be a simple and obvious solution to keep customers on TOU rates, while also ensuring the additional benefits captured by the improved price signals of the E-28 plan.

WRA recommends that rather than moving EZ-3 customers into the E-23 plan, EZ-3 customers should be moved into the E-28 plan, which is also a TOU plan.

3. Further Tailoring the E-28 Plan to Fully Capture the benefits of Charging EV Customers

The E-28 tariff is particularly well suited for EV owners who are able to charge their vehicle at home during the 8am to 3pm super off-peak period. The lower price during the super off-peak period will help to maximize fuel cost savings that EVs have over traditional vehicles. Polling has repeatedly

[22] *Id*. at 72.
[23] *Id*. at 64.
[24] *Id*. at 68.

demonstrated that one of the most attractive elements of purchasing an EV for prospective EV customers is the fact that EVs are much cheaper to fuel and maintain.[25] Charging during the super off-peak period of the E-28 rate will maximize this benefit for EV drivers. Assuming the average driving characteristics for an Arizonan,[26] a customer charging an EV entirely during the super off-peak period would save $1,338.82 per year when compared to fueling their vehicle with gasoline.[27] This equates to $0.01 per mile charging on the super off-peak period, as compared to $0.12 per mile powering the vehicle with gasoline. Not only does the super off-peak rate offer great cost savings, but it also maximizes the environmental benefits when, as discussed above, solar generation is at or close to its maximum generation. Thus, the super off-peak period in the E-28 tariff is very beneficial for EV drivers, the environment, and SRP.

For the EV drivers who can't charge during midday hours, the price signal to delay charging from on-peak (6pm-9pm) until the off-peak hours (9pm-8am) is relatively modest, although it represents an improvement over the Basic Price Plan (E-23) in terms of incentivizing better evening and early morning charging. The small differentiation between on-peak and off-peak (off-peak is an approximately 20% discount over the on-peak pricing per kWh) and a short peak period means that for customers returning home from a traditional "9 to 5" job, it will only cost them a couple of cents a day to plug in immediately upon returning home. WRA recommends that Management increase the price differentiation between on-peak and off-peak rates, which could better help incentivize optimal behaviors for those who do not have the option to charge during the day. In the future, more advanced managed charging programs – like those being deployed by other utilities across the country – should

[25] *Top 5 Reasons Drivers are Choosing EVs*, New York State Energy Research and Development Authority, https://www.nyserda.ny.gov/Featured-Stories/Top-5-Reasons-Drivers-Are-Choosing-EVs; *2024 EV Driver Annual Survey Report*, Plug in America 9-11, https://pluginamerica.org/wp-content/uploads/2024/09/2024-Plug-In-America-EPRI-EV-Driver-Survey-Report_Final.pdf.

[26] Assuming the average mileage driven by an Arizonan (13,090 miles per year), average cost of gasoline in Arizona taken on January 13th, 2025 ($3.05), and average miles per gallon (26.4 miles per gallon) of an American vehicle.

[27] *Average Miles Driven per Year by Americans*, Voom, https://www.voominsurance.com/rideshare-insurance/average-miles-driven-per-year-by-americans#:~:text=Arizona:%20About%2013%2C090%20miles,Colorado:%20About%2012%2C899%20miles; *Fuel Prices*, American Automobile Association, https://gasprices.aaa.com/?state=AZ; *Model Year 2022 Light-Duty Vehicles Sold in the U.S. Averaged 26.4 Miles per Gallon*, U.S. Department of Energy (Sep. 4. 2023), https://www.energy.gov/eere/vehicles/articles/fotw-1306-september-4-2023-model-year-2022-light-duty-vehicles-sold-us#:~:text=Miles%20Per%20Gallon-,FOTW%20%231306%2C%20September%204%2C%202023:%20Model%20Year%202022,miles%20per%20gallon%20(mpg).&text=of%20.

be considered by SRP as a way to ensure that EV charging occurring in the evening hours is being dynamically managed to align with low-cost and low-emission hours.

While E-28 represents a great step forward toward incentivizing optimal daytime charging, more can be done to ensure that evening and early morning charging happens during optimal hours. WRA recommends that SRP also develop managed charging programs in the future which can dynamically adjust EV charging in response to actual grid conditions. These types of programs have been implemented by SRP's peers both across the country and within Arizona, with utilities like Tucson Electric Power in the stages of standing up managed charging programs. When customers are enrolled in a managed charging program, they simply sign up for the program and clarify what time they want their battery fully charged by. Upon coming home, they plug in their vehicle and the program picks the best time to charge the vehicle in response to grid conditions. This allows for charging to happen later in the evening or in the early morning in a manner which aligns EV charging with hours when electricity has relatively lower emissions and/or system costs and allows for better environmental and grid outcomes than could happen by simply aligning with the off-peak E-28 hours. Utilities like Xcel Energy, Eversource Connecticut, and Baltimore Gas and Electric have developed advanced managed charging programs[28] which can be considered as a good model for how to maximize flexible EV load for the grid and reduce emissions associated with EV charging while providing a seamless customer experience.

WRA recommends that the Board direct Management to increase the price differentiation between the proposed on-peak and off-peak rates and consider developing managed charging programs in the future.

III. Adding Sustainability to SRP's Pricing Principles for Future Pricing Processes

In December of 2000, the Board adopted five "Pricing Principles" to guide SRP's electric services pricing strategies and tariff design.[29] These pricing principles include: 1) Cost Relation, which SRP describes as the establishment of prices in relation to costs; 2) Gradualism, which embraces stabilizing price levels and smoothing the impact of cost impacts for customers; 3) Equity, which SRP defines as the treatment of all customers in an economically fair manner; 4) Choice, which seeks to improve

[28] *The State of Managed Charging in 2024*, SMART ELECTRIC POWER ALLIANCE 38-45, https://sepapower.org/wp-content/uploads/2024/08/SEPA-State-of-Managed-Charging-2024-Report_print.pdf.
[29] *Id.* at 11 (Financial Market and Capital Structure).

customer satisfaction through creative pricing structures; and 5) Sufficiency, which SRP defines as enabling SRP to recover the cost of system assets and maintain its financial well-being.[30] WRA recommends that SRP build upon the foundation of these principles and add Sustainability to its pricing principles to guide future pricing processes. It is now timely, 25 years later, to update those principles and incorporate Sustainability.

WRA is not suggesting that SRP has not used Sustainability as a guiding principle during this Pricing Process, rather WRA is only asking that the importance of that principle is endorsed and made official by the current Board. WRA believes that Management will support this request, as several elements of its new Proposed Adjustments are designed to support sustainability goals. For example, as explained above, the Company's updated TOU rates with daytime super off-peak pricing are designed to optimize utilization of solar energy and to reduce curtailment and system emissions. In his announcement of the SRP Pricing Process, Chief Executive Officer Jim Pratt stated that "SRP Management's proposal reflects increases in the company's operational costs driven by needed improvements to the electric grid to maintain reliability and meet our ***ambitious sustainability and decarbonization goals***, by rising labor costs and by important customer service enhancements."[31] (emphasis added). Additionally, Management has stated that Sustainability is the guiding principle for several of its proposed programs, including the Carbon Reduction Rider[32] and the Energy Certificate Attribute Rider.[33] Moreover, Sustainability is a key element informing SRP's Integrated System Plan process.[34]

SRP customers also support SRP's efforts to be sustainable. In a survey of SRP customers conducted by WRA in 2023, WRA found that:

- **A majority of SRP customers (60%) prefer renewable energy** as the source of their home's power, followed by nuclear (21%) and fossil fuel energy (14%).

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[30] *Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle* at 27.
[31] Schuricht, *SRP Initiates Pricing Process that Seeks Price Increase and New Price Plan Options*, SRP (Dec. 2, 2024), https://www.srpnet.com/assets/srpnet/pdf/price-plans/2024/2024%20Price%20Process%20Opens%20News%20Release%20FINAL.pdf.
[32] *Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle* at 168 (stating that through the Energy Attribute Certificate Rider "the customer may purchase RECs or participate in SRP's retirement of RECs, in either case associated with energy generated from renewable resources selected by SRP.").
[33] *Id*. at 164 (stating that the Carbon Reduction Rider is for customers who wish "to support the reduction or removal of carbon dioxide emissions").
[34] *Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle* at 10.

- Additionally, **59% of SRP customers think that the utility should prioritize closing old fossil fuel-powered plants** and invest instead in clean energy right here in Arizona to create thousands of jobs and strengthen our local economy.

- Less than a quarter of customers (23%) report awareness of existing efforts by SRP to reduce pollution – **yet a plurality (44%) thinks the utility should be doing more to reduce pollution**.

- **SRP ratepayers think investments in clean energy over fossil fuels will improve public health and pollution (64%)** but are split over whether this will lower (37%) or raise (42%) utility bills (16% think there would be no impact).

SRP's endorsement of Sustainability as one of its pricing principles is an easy way that the Board can help to effectuate positive change in line with the interests of both SRP's Management and customers. Including Sustainability as a guiding principle for ratemaking also aligns with the prominence of this objective in the SRP's resource planning process.[35] As a result, WRA recommends that the Board officially add "Sustainability" as its sixth pricing principle and foster an inclusive conversation around what "Sustainability" will mean to SRP in the shaping of its pricing proposals moving forward.

IV. Energy Attribute Certificate Rider

Management is proposing to update and expand the existing Renewable Energy Credit Pilot Rider, renaming it the Energy Attribute Certificate Rider.[36] The Management proposal would expand this rider beyond Renewable Energy Certificates to include other energy attribute certificates, but only explicitly mentions the addition of Zero-Emission Credits.[37] Under the Energy Attribute Certificate Rider, customers "may participate in SRP programs under which the customer may purchase RECs or participate in SRP's retirement of RECs, in either case associated with energy generated from renewable resources selected by SRP." WRA does not oppose the newly updated rider but does want to bring attention to some of its features.

[35] *2023 Integrated System Plan* at 7, https://www.srpnet.com/assets/srpnet/pdf/grid-water-management/grid-management/isp/SRP-2023-Integrated-System-Plan-Report.pdf.
[36] *Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle* at 168.
[37] *Id*.

1. Renewable Energy Certificates

A Renewable Energy Certificate, often called a Renewable Energy Credit ("REC") represents all of the non-energy attributes associated with a megawatt-hour ("MWh") of electricity generated from an eligible energy resource.[38] RECs play an important role in accounting, tracking, and assigning ownership to renewable electricity generation and use.[39] These RECs legally convey the non-energy attributes of renewable electricity generation, including the emissions profile of that generation, to their owner and serve as the basis for a renewable electricity consumption claim.[40] RECs are a marketable commodity, vesting a valuable property right with the REC holder.[41]

In Arizona, the regulation of RECs is located in the Administrative Codes.[42] A.A.C. R14-2-1803 defines what a REC legally means in Arizona, how those RECs can be conveyed, and how the transfer of RECs should be documented and verified.[43] Unfortunately, the Arizona Corporation Commission has taken steps recently to repeal the administrative codes related to RECs [44], which would remove the legal concept of RECs from Arizona. What remains are Retail RECs. Retail RECs are similar to RECs created legally under a state authority, as they represent the legal property rights to the environmental attributes of one MWh of renewable electricity generation.[45] Unlike RECs created by state code, Retail RECs are entirely market-based,[46] and unbundled Retail RECs are market-based RECs that are "sold, delivered, or purchased separately from electricity."[47]

The sale of unbundled RECs is the most common form of green power purchasing in the voluntary market today.[48] However, the sale of unbundled Retail RECs has little real-world impact, as it

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[38] *Renewable Energy Certificates,* U.S. ENVIRONMENTAL PROTECTION AGENCY, https://www.epa.gov/green-power-markets/renewable-energy-certificates-recs.
[39] *Id.*
[40] *Guidelines for Renewable Energy Claims,* CENTER FOR RESOURCE SOLUTIONS (Feb. 26, 2015), https://resource-solutions.org/wp-content/uploads/2015/07/Guidelines-for-Renewable-Energy-Claims.pdf.
[41] Letter from James A. Kohm, Assoc. Dir., Div. of Enf't, Bureau of Consumer Prot., to R. Jeffrey Behm, Esq., Sheehey, Furlong & Behm, P.C. (Feb. 5, 2015), https://www.ftc.gov/system/files/documents/public_statements/624571/150205gmpletter.pdf.
[42] A.A.C. R14-2-1803.
[43] *Id*.
[44] Docket RE-00000A-24-0026, https://edocket.azcc.gov/search/docket-search/item-detail/28090.
[45] *Retail RECs*, U.S. ENVIRONMENTAL PROTECTION AGENCY, https://www.epa.gov/green-power-markets/retail-recs#:~:text=RECs%20are%20tradeable%2C%20market%2Dbased,MWh)%20of%20renewable%20electricity%20generation.
[46] *Id*.
[47] *Id*.
[48] Naik, *Problematic corporate purchases of clean energy credits threaten net zero goals*, S&P GLOBAL (May 5, 2021), https://www.spglobal.com/esg/insights/problematic-corporate-purchases-of-clean-energy-credits-threaten-net-zero-goals.

does not help to displace fossil fuel generation and does not do much to help decarbonize the grid.[49] Unbundled Retail RECs allow organizations to legally make a claim that their energy is derived from renewable sources even if the direct energy that organization uses is derived from fossil fuel sources.[50] A paper published in 2022 found that a group of companies had reported a combined emissions reduction of 30.7% resulting from REC purchases, but upon closer inspection had an actual emissions reduction closer to 9.9%.[51] Unbundled Retail RECs fail to capture the local benefits derived from renewable energy, as the generation of each REC could be hundreds of miles away while locally the power comes largely from heavily emitting fossil fuel sources.[52]

As SRP is an electricity supplier, WRA recommends that in its administration of the new Energy Attribute Certificate Rider, SRP focus on energy and non-energy attributes that it can track and convey corresponding to renewable energy generated on its own system, not generated originating from outside of Arizona, which does not contribute to Arizona's or SRP's efforts to decarbonize. WRA also recommends that the Board carefully consider the sale of unbundled Retail RECs to business customers through SRP's REC Select program.[53]

2. Zero-Emission Credits

Management explicitly mentions one other energy attribute certificate, Zero-Emission Credits ("ZECs"), that it plans to include in its proposed Energy Attribute Certificate Rider. Unlike RECs, ZECs are not regulated in Arizona and have no legal basis at the state level in Arizona. It appears that ZECs are credits generated with each MWh of electricity produced by nuclear power plants.[54] ZEC programs were originally designed to compensate nuclear power plants for the production of carbon free energy.[55] The first ZEC programs were introduced in New York and Illinois and required utilities to

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[49] *Id*.
[50] Bergamo, *Renewable Energy Credits: Decarbonizing the Grid or Just a Corporate Messaging Tool?*, UNIVERSITY OF PENNSYLVANIA (June 12, 2023), https://kleinmanenergy.upenn.edu/commentary/blog/renewable-energy-credits-decarbonizing-the-grid-or-just-a-corporate-messaging-tool/#:~:text=The%20most%20puzzling%20aspect%20of,had%20little%20to%20no%20impact.
[51] *Id*.
[52] Hughes & Huestis, *Clean Energy 101: The REC Market*, RMI (June 2, 2022), https://rmi.org/clean-energy-101-the-rec-market/.
[53] *2024 Annual Report* at 2-3, https://www.srpnet.com/assets/srpnet/pdf/about/2024-annual-report.pdf.
[54] *Zero-Emission Credits*, NUCLEAR ENERGY INSTITUTE 3 (April 2018), https://www.nei.org/corporatesite/media/filefolder/resources/reports-and-briefs/zero-emission-credits-201804.pdf.
[55] Valetta, *Zero Emissions Credits: An Overview*, UNIVERSITY OF PENNSYLVANIA (Aug. 31, 2017), https://kleinmanenergy.upenn.edu/commentary/blog/zero-emissions-credits-an-overview/.

purchase ZECs from specified in-state nuclear power plants from the wholesale market.[56] ZEC programs now exist in five states.[57] As Arizona does not have a state-defined ZEC program, it is unclear how SRP's planned use of ZECs would be administered to customers.

To clarify the uncertainties in SRP's proposed Energy Attribute Certificate Rider program, WRA submitted questions to Management, but has not received responses as of this writing. In order for WRA to provide specifically applicable recommendations for SRP's use of RECs and other energy attribute certificates, a great deal of more information is needed.

As such, WRA recommends that the Board require that Management provide greater detail about SRP's possible use of ZECs and any other energy attribute rider.

V. SRP's Decarbonization Efforts and the Carbon Reduction Rider

Management is proposing a new Carbon Reduction Rider which the Company states is intended to allow customers wishing to support SRP's efforts to decarbonize the opportunity to participate in programs developed by SRP to that effect. However, this rider does not actually provide direct emissions reductions nor direct participation in decarbonization programs. The rider itself purports to accomplish this effect through the "***purchase, use, or retirement of offsets, allowances, or credits*** associated with the ***reduction, removal, avoidance, capture, or sequestration of carbon dioxide emissions."***[58] (emphasis added). Evidence shows that the Carbon Reduction Rider is not only incongruent with its purported purpose but is also in contradiction with SRP's intent to decarbonize as a whole.

As a result, WRA urges the Board to reject this proposed Carbon Reduction Rider or, at the very least, substantially revise it so that customer funds only go to SRP Programs that actually reduce carbon emissions. These programs would not include the purchase of offsets or the capture or sequestration of carbon dioxide from fossil fuel generation sources like coal.

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[56] *Id*.
[57] *State Subsidies for Zero-Emissions Credits*, GAIN, https://gain.inl.gov/our-work/existing-nuclear-fleet/state-subsidies-for-zero-emissions-credits/.
[58] *Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle* at 164.

1. SRP's Sustainability Goals

SRP's Sustainability Goals were originally approved in 2019 and are evaluated and updated every five years.[59] SRP recently updated its goals in 2024, and now has revised goals that will go into effect in May of 2025.[60] The revised Sustainability Goals, which were established through a collaborative stakeholder process, include an intensity based goal of 82% reduction of CO_2 per MWh from 2005 levels.[61] An intensity based goal is a metric that sets an organization's emissions reduction target relative to an operational variable.[62] This enables SRP to set reduction targets while accounting for growth.[63] Unfortunately, setting, or even reaching, an intensity based goal does not ensure that actual tons of carbon reductions occur.[64] Indeed, an organization can actually increase emissions measured as tons of CO_2 while still meeting an intensity based goal.

SRP also has a mass-based goal.[65] A mass-based goal is one that aims to reduce an organization's total carbon emissions by a set quantity by a set time.[66] SRP plans to reduce emissions from facilities by 45% from a 2016 baseline by 2035. SRP also has a goal to have net-zero emissions by 2050.[67] In order to meet these goals, SRP will need to retire coal resources and add significant amounts of clean energy resources.[68] Notably, SRP's Sustainability Goals make no mention of reaching any of these decarbonization goals through the purchase of offsets or through the use of carbon sequestration technology applied to heavily emitting fossil fuel resources like coal plants.

2. Offsets and Carbon Credits

The proposed Carbon Reduction Rider fails to contribute to either the retirement of SRP's coal resources or the addition of clean energy capacity to SRP's resource mix. Rather, the Carbon Reduction Rider claims to achieve the reduction of carbon emissions through, in part, the "purchase, use, or

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[59] *SRP 2035 Sustainability Goals Update Process*, https://www.srpnet.com/grid-water-management/future-planning/goal-process.
[60] *Id*.
[61] *SRP 2035 Sustainability Goals* at 2.
[62] *Target Setting,* United States Environmental Protection Agency, https://www.epa.gov/green-power-markets/target-setting#:~:text=Absolute%20targets%20aim%20to%20reduce,while%20accounting%20for%20economic%20growth.
[63] *Id.*
[64] *Id*.
[65] *SRP 2035 Sustainability Goals* at 2.
[66] *Absolute vs. intensity based carbon targets – The lowdown*, SWEEP (Oct. 7, 2024), https://www.sweep.net/insights/absolute-vs-intensity-based-carbon-targets-the-lowdown.
[67] *SRP 2035 Sustainability Goals* at 2-3.
[68] *SRP 2023 Integrated System Plan* at 16, https://www.srpnet.com/assets/srpnet/pdf/grid-water-management/grid-management/isp/SRP-2023-Integrated-System-Plan-Report.pdf.

retirement of offsets, allowances, or credits."[69] The purchase of offsets is not a suitable replacement for SRP taking steps to reduce operational reliance on fossil fuel resources like coal and methane gas while increasing its reliance on cleaner renewable alternatives. Studies have readily shown that reliance on offsets to meet carbon reduction goals is legally and logistically a risky endeavor at best.[70]

3. Carbon Offset Markets

Carbon offsets are a relatively new concept that many companies with ambitious net-zero targets are turning to, with the hope that offsets might neutralize large chunks of their own emissions through the purchase of carbon credits.[71] The appeal of carbon offsets is easy to see: the hope is that an organization can avoid costly investment and adaptation through the purchase of credits, which account for the avoidance or even removal of emissions elsewhere.[72] There are two types of carbon offsets or carbon credit markets. A compliance or mandatory market is a market regulated by an international, national, or regional carbon reduction regime.[73] Voluntary markets, on the other hand, are not regulated and as a result come with a significant number of added risks.[74] Chief among these risks is that an organization may be purchasing carbon credits which do not actually reduce or remove emissions.

An organization buying carbon credits from the voluntary market must avoid several pitfalls to receive value in carbon credits that achieve an actual climate impact. First, the most important thing an organization must verify is that a carbon credit achieves additionality.[75] For a carbon credit to have additionality it must achieve emissions reductions which would not have otherwise occurred without the revenue generated by selling the offset.[76] Second, a carbon credit cannot overestimate or oversell the emission reductions it will achieve.[77] Third, if the carbon credit accounts for only historical mitigation activities, it fails to promote new decarbonization projects beyond those already

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[69] *Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle* at 164.
[70] Naik & Whieldon, *Carbon offsets prove risky business for net zero targets*, S&P GLOBAL (May 12, 2021), https://www.spglobal.com/esg/insights/carbon-offsets-prove-risky-business-for-net-zero-targets.
[71] *Id*.
[72] *Id*.
[73] *Id*. (Stating that California's cap-and-trade program, which starts with a cap on the total number of emissions companies subject to the program can directly produce annually and then lowers that cap over time with penalties for noncompliance is an example of one such compliance market).
[74] *Id*.
[75] Trencher et. al., *Demand for low-quality offsets by major companies undermines climate integrity of the voluntary carbon market*, NATURE COMMUNICATIONS 2 (Aug. 10, 2024), https://www.nature.com/articles/s41467-024-51151-w.
[76] *Id*. at 1.
[77] *Id*. at 2.

established.[78] Fourth, most of the inexpensive carbon credits available on the market originate from over-credited projects that have little value and little additionality.[79] Finally, carbon offsets that propose to further promote renewable technologies in countries which already have widely adopted projects and standardized practices have a weak argument for additionality.[80] Carbon credits should instead focus on projects set to occur where renewable energy is not yet common due to financial, technological, or policy hurdles.[81]

4. The Pitfalls of Carbon Offsets

Unfortunately, carbon credits in voluntary markets overwhelmingly fail to meet some, if not all, of these criteria. Sellers of carbon credits must source those credits from a real emissions reduction project, where the relevant investments and emissions are tracked and traceable. But an investigation from 2023 found that a vast majority of the environmental projects used for offsets appear to have fundamental flaws and therefore cannot be used to reliably cut emissions.[82] The investigation was conducted by a corporate watchdog that analyzed the top 50 emission offset projects in the global market[83] and found that very few may actually provide the claimed emissions reductions sold to buyers:

- **"A total of 39 of the top 50 emission offset projects, or 78% of them, were categorized as likely junk[84]** or worthless due to one or more fundamental failing that undermines its promised emission cuts.
- **Eight others (16%) look problematic**, with evidence suggesting they may have at least one fundamental failing and are potentially junk, according to the classification system applied.

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[78] *Id*.
[79] *Id*.
[80] *Id*.
[81] *Id*.
[82] Lakhani*, Revealed: top carbon offset projects may not cut planet-heating emissions*, THE GUARDIAN (Sep. 19, 2023), https://www.theguardian.com/environment/2023/sep/19/do-carbon-credit-reduce-emissions-greenhouse-gases.
[83] *Id*.; Projects included "forestry schemes, hydroelectric dams, solar and wind farms, waste disposal and greener household appliances schemes."
[84] *Id*.; Projects were classified as "junk" if "there was compelling evidence, claims or high risk that it cannot guarantee additional, permanent greenhouse gas cuts among other criteria"

- **The efficacy of the remaining three projects (6%) could not be determined definitively** as there was insufficient public, independent information to adequately assess the quality of the credits and/or accuracy of their claimed climate benefits.
- **Overall, $1.16bn of carbon credits have been traded so far from the projects classified by the investigation as likely junk or worthless**; a further $400m of credits bought and sold were potentially junk."[85]

Further, more than a third of the top 50 projects were found to have three or more fundamental failings. These projects account for a third of the entire global carbon market.[86] For example, a forestry project in Zimbabwe was reported to likely shift emissions elsewhere and overestimated what its emissions reduction would be by five to 30-fold.[87] In Wyoming, one of the world's largest carbon capture and storage plants was found to have released the vast majority of the project's captured CO_2 into the atmosphere or sold the CO_2 to fossil fuel companies to help extract hard-to-reach oil, resulting in more emissions, not less.[88]

At the heart of the ongoing and pervasive issues with the voluntary carbon market are the handful of groups that create registries in accordance with their own standards which fail to uphold basic criteria that would ensure projects achieve actual carbon emission reductions.[89] Studies have found that these registries, which include organizations like Verra, the Gold Standard Registry, the American Carbon Registry, and the Clean Development Mechanism, are full of ineffective carbon credits.[90] One such study, which covered almost 300 carbon offset projects, found that the industry's top registries had consistently allowed developers to claim far more climate-saving benefits than was justified.[91] Another study found that 28 out of 50 projects certified by Verra were junk and another four were problematic.[92] Two out of four projects from the Gold Standard Registry were classified as

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[85] *Id*.
[86] *Id*.
[87] *Id*.
[88] *Id*.; *Shute Creek – world's largest carbon capture facility sells CO2 for oil production, but vents unsold*, INSTITUTE FOR ENERGY ECONOMICS AND FINANCIAL ANALYSIS (March 1, 2022), http://ieefa.org/articles/shute-creek-worlds-largest-carbon-capture-facility-sells-co2-oil-production-vents-unsold.
[89] White*, Bogus Carbon Credits are a 'Pervasive' Problem, Scientists Warn*, TIME (March 21, 2023), https://time.com/6264772/study-most-carbon-credits-are-bogus/.
[90] *Id*.; Lakhani, *supra* note 82.
[91] White, *supra* note 89.
[92] Lakhani, *supra* note 82.

likely junk from a carbon credit perspective and five of eight projects were classified as junk from the Clean Development Mechanism.[93]

5. Carbon Capture and Sequestration

The Carbon Reduction Rider also proposes to allow SRP customers wishing to support the reduction or removal of carbon dioxide emissions to participate in programs concerning the ***"capture, or sequestration of carbon dioxide emissions."*** [94] (emphasis added). While information about this aspect of the Carbon Reduction Rider is scarce in the material provided to the public, the implication here is that SRP will be adopting carbon capture and sequestration technology for its fossil fuel resources. Although this may reflect a commitment by SRP to directly invest in carbon capture technology on its own electric system, the use of carbon sequestration to meet SRP's carbon reduction goals is highly problematic. While carbon capture technology likely has a role to play in the world's efforts to decarbonize, that role is best suited for hard-to decarbonize industries such as the cement and steel industries, where suitable alternative technologies or materials are not available or fully developed.[95] Carbon sequestration is also not a mature commercial technology for electric generation, is very expensive,[96] is not 100% effective[97], and has been shown to actually increase net air pollution from plants where it is used.[98]

6. An Overview of Carbon Capture and Sequestration Technology

There are many variations of carbon capture and sequestration ("CCS") technology.[99] The CCS technology most relevant for SRP is the installation of equipment in a coal or methane gas power facility to remove CO_2 from exhaust and either sequester it underground or in a material, or sell it for industrial use.[100] CCS technology has been in commercial use for several decades and was originally

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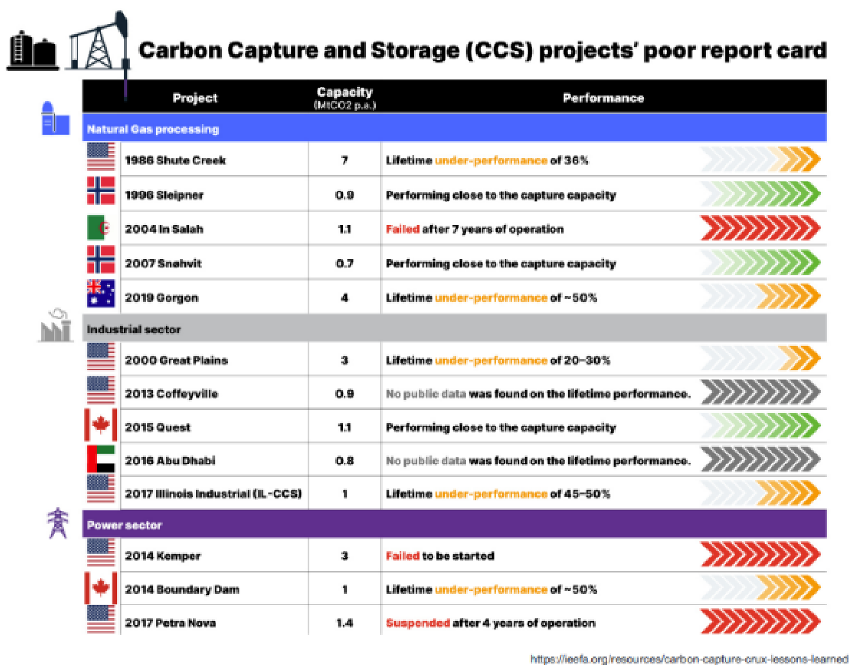
[93] *Id*.
[94] *Proposed Adjustments To SRP's Standard Electric Price Plans Effective With The November 2025 Billing Cycle* at 164.
[95] Cameron et. al., *Why the Cost of Carbon Capture and Storage Remains Persistently High*, IISD (Sept. 7, 2023), https://www.iisd.org/articles/deep-dive/why-carbon-capture-storage-cost-remains-high.
[96] *Id*.
[97] *Carbon capture and storage: Where are we at?*, ZERO CARBON ANALYTICS (Sept. 29, 2022), https://zerocarbon-analytics.org/archives/energy/carbon-capture-and-storage-where-are-we-at.
[98] *Id*.; Jacobson, *The health and climate impacts of carbon capture and direct air capture*, 12 ENERGY ENVIRON. SCI. 3567, 3567 (2019).
[99] Douglas, *Why carbon capture is no easy solution to climate change*, REUTERS (Nov. 27, 2023), https://www.reuters.com/business/environment/why-carbon-capture-is-no-easy-solution-climate-change-2023-11-22/.
[100] Jacobson, *supra* note 98.

developed for capturing CO_2 for the enhanced recovery of oil by extending the production and life of oil wells.[101] According to a December 2024 presentation by the Institute for Energy Economics and Financial Analysis, there are about 30 active CCS projects in the world.[102] Of those thirty projects, only two in the world are integrated with coal-fired power plants and capturing any CO_2.[103] No CO_2 has been captured at a commercial-sized methane gas power plant.[104]

Despite what amounts to largely a failure of CCS technology's implementation in the power sector,[105] CCS technology has still been lauded as a silver bullet by, most notably, the oil and gas industries.[106] Indeed, the top leaders of organizations developing CCS projects are all oil companies: ExxonMobil, TotalEnergies, Eni, Equinor, and Shell.[107] Considering that nearly three-quarters of all CO_2 captured annually is reinjected into the ground for enhanced oil recovery to produce even more oil and gas, this support is not surprising.[108] Those wishing to buy into the ideal of CCS should first consider CCS's unreasonable expense,[109] low effectiveness[110], safety risks,[111] and notably its likelihood to actually increase air



[101] Cameron et. al., *supra* note 95.
[102] Morrison, *The Good, the Bad, and the Ugly reality about CCS (Carbon Capture and Storage)*, INSTITUTE FOR ENERGY ECONOMICS AND FINANCIAL ANALYSIS 13 (Dec. 3, 2024), https://ieefa.org/sites/default/files/2024-03/CCSpresentation4-MPCMarch24_CK.pdf.
[103] *Id*.
[104] *Id*.
[105] *Carbon capture and storage: Where are we at?*, ZERO CARBON ANALYTICS (Sept. 29, 2022), https://zerocarbon-analytics.org/archives/energy/carbon-capture-and-storage-where-are-we-at.; Morrison, *supra* note 102 at 11.
[106] Abreu, *Comment: Carbon capture and storage is a dangerous distraction. It's time to imagine a world beyond fossil fuels*, REUTERS (Dec. 11, 2023), https://www.reuters.com/sustainability/climate-energy/comment-carbon-capture-storage-is-dangerous-distraction-its-time-imagine-world-2023-12-11/.
[107] *Carbon capture and storage: Where are we at?*, ZERO CARBON ANALYTICS (Sept. 29, 2022), https://zerocarbon-analytics.org/archives/energy/carbon-capture-and-storage-where-are-we-at.
[108] Abreu, *supra* note 106.
[109] Douglas, *supra* note 99.
[110] Morrison, *supra* note 102 at 11.
[111] Abreu, *supra* note 106.

pollution, not reduce it.[112]

7. The Pitfalls of Carbon Capture and Sequestration

One obstacle facing the diffusing of CCS is its high costs.[113] Unlike the downward trend in the cost of renewables, the cost of CCS has persistently remained high for nearly 40 years.[114] This is likely because of two factors: 1) CCS's design complexity; and 2) CCS's need for high customization.[115] Technologies with high design complexity have a large number of technical components with a great deal of interrelation between those components.[116] This makes innovation much more difficult to achieve and results in a high risk of bottlenecks and dead ends.[117] CCS technology also requires a great deal of customization.[118] Components of CCS often need to be tailored to specified applications, geological conditions, and supply chains.[119] This also limits innovation and hinders large-scale deployment.[120] The retrofit of the W.A. Parish Coal Power Plant in Texas cost $1 billion dollars or $4200 per kW, beyond the costs of the coal plant itself.[121] This is about 74% of the capital cost of a new coal plant.[122] A report from the Institute for Energy Economics and Financial Analysis shows that thermal power generation with CCS has a levelized cost of electricity at least 1.5-2 times above alternatives like renewable energy.[123]

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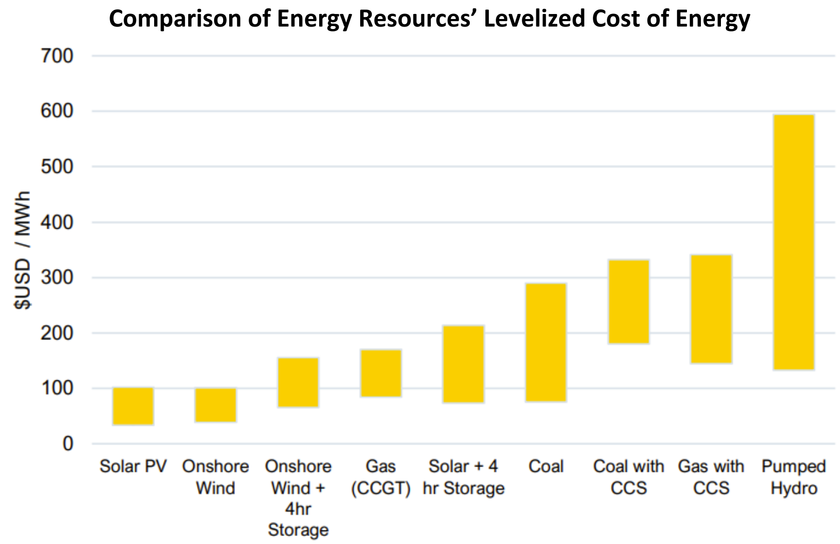
[112] Jacobson, *supra* note 98 at 12.
[113] Cameron et. al., *supra* note 95.
[114] Way, *Heavy dependence on Carbon Capture and Storage 'highly economically damaging', says Oxford report*, UNIVERSITY OF OXFORD (Aug. 2023), https://www.smithschool.ox.ac.uk/news/heavy-dependence-carbon-capture-and-storage-highly-economically-damaging-says-oxford-report.; Cameron et. al., *supra* note 95.
[115] Cameron et. al., *supra* note 95.
[116] *Id*.
[117] *Id*.
[118] *Id*.
[119] *Id*.
[120] *Id*.
[121] Jacobson, *supra* note 98 at 3568.
[122] *Id*. at 3569.
[123] Salt & Ng, *CCS For Power Yet to Stack Up Against Alternatives*, THE INSTITUTE FOR ENERGY ECONOMICS AND FINANCIAL ANALYSIS 18 (Mar. 2023), https://ieefa.org/sites/default/files/2023-03/IEEFA%20Report%20-%20CCS%20for%20power%20yet%20to%20stack%20up%20against%20alternatives_March2023.pdf.



In other words, adding CCS to electricity generating units increases the cost of energy substantially while significantly reducing generation plant efficiency. The transport, storage, monitoring, verification, and any additional compliance and liability costs of operating CCS technology should also be taken into account.[124]

A thermal resource with CCS is not only one of the costliest forms of energy available today, it is also a technology that underperforms on its promise to capture carbon emissions.[125] CCS technology necessarily requires additional energy to function, which is known as an energy penalty.[126] The energy penalty of running CCS technology on a coal power plant is about 20-25% of the plant's net energy output.[127] To address this energy penalty, the W.A. Parish Coal Plant added a natural gas turbine to its facility.[128] While this turbine decreased the energy penalty to the coal plant itself, it had the added effect of increasing overall emissions, which in turn decreased the capture percentage of the carbon emissions.[129] Further, the implementation of CCS technology at the W.A. Parish Plant actually increased overall air pollution by 25%, including non-carbon pollutants that negatively affect health.[130]

A review of the W.A. Parish Coal Power Plant demonstrated that taking into account direct emissions, only an average of 55.4% of carbon was captured from coal combustion CO_2, not the 90% that was promised.[131] When including the emissions of the coal plant and the emissions from the

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[124] *Id*. at 12.
[125] Morrison, *supra* note 102, at 11.
[126] *Carbon capture and storage: Where are we at?*, ZERO CARBON ANALYTICS (Sep. 29, 2022), https://zerocarbon-analytics.org/archives/energy/carbon-capture-and-storage-where-are-we-at.
[127] Herzog, *If a fossil fuel power plant uses carbon capture and storage, what percent of the energy it makes goes to the CCS equipment?*, CLIMATE MIT (Mar. 28, 2024), https://climate.mit.edu/ask-mit/if-fossil-fuel-power-plant-uses-carbon-capture-and-storage-what-percent-energy-it-makes.
[128] Jacobson, *supra* note 98 at 3568.
[129] *Id*. at 3568-69.
[130] *Id*. at 3569.
[131] *Id*.

installed methane gas turbine, the capture rate lowered to 33.9%. Further, if upstream emissions were included from the mining and processing of the coal fuel used at the plant, the net recovery of carbon emissions was only estimated to reach 10.8% over the course of 20 years.[132]

A review of existing CCS projects also highlights the added safety risks that carbon storage in particular can have.[133] The Sleipner and Snohvit CCS projects both experienced dangerous safety risks.[134] At the Snohvit Project, problems occurred just 18 months after injection operations began, despite detailed field assessments and engineering before the project began operating.[135] The project operators suddenly realized that a geological structure which was estimated to have 18 years' worth of CO_2 storage capacity actually had less than six months left of storage potential when the site began demonstrating "acute signs of rejecting the stored CO_2."[136] Emergency remedial actions had to be taken at great cost to the operating entity.[137] Three years into Sleipner's storage operations, CO_2 had already migrated from a lower injection point to the top of the storage formation and into a previously unidentified shallow layer.[138] Luckily the shallow layer was geologically bound, but if it had not been, CO_2 would have leaked from the site.[139]

Given the technical challenges and high costs of CCS projects, it is difficult to imagine how a Carbon Reduction Rider might collect sufficient revenue from SRP to effectively launch a successful CCS project that results in meaningful CO_2 emissions reductions on the SRP system. Until such a CCS project can go online and provide real emissions reductions, SRP customers who buy into the proposed Carbon Reduction Rider would instead by paying to support extending the life of polluting generation plants rather than actual emissions reductions.

8. SRP's Decarbonization Efforts

The Carbon Reduction Rider proposed by Management is flawed at its very foundation. There are many different kinds of programs that SRP could use to enable its customers to assist in

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[132] *Id*.
[133] Abreu, *supra* note 106.
[134] Hauber, *Norway's Sleipner and Snohvit CCS: Industry models or cautionary tales?,* INSTITUTE FOR ENERGY ECONOMICS AND FINANCIAL ANALYSIS (June 2023), https://ieefa.org/resources/norways-sleipner-and-snohvit-ccs-industry-models-or-cautionary-tales.
[135] *Id.*
[136] *Id.*
[137] *Id.*
[138] *Id.*
[139] *Id.*

decarbonization. Those programs should not include either the funding of questionable CCS technology to extend the life of heavily emitting coal facilities or the purchase of unreliable carbon offsets. SRP's use of customer funds to invest in these kinds of programs could result in customer backlash if these programs are identified as merely an elaborate way of greenwashing SRP's continued reliance on fossil fuels. Unfortunately, the adoption of the Carbon Reduction Rider could be worse than greenwashing if it diverts funds and resources away from real solutions that could actually assist SRP's efforts to decarbonize through direct emissions reductions on the SRP system.

Customer funds acquired to support emissions reductions should not be used to extend the life of heavily emitting coal power plants. While, as mentioned above, CCS has a chance of slightly reducing carbon emissions at great additional cost, the use of CCS does not increase the capture of other air pollutants and actually has a risk of increasing that pollution.[140] For example, coal plants are a major source of fine particulate matter pollution, which is associated with increased risk of death.[141] The particulate matter emitted from coal plants is likely even more deadly than particulate matter from other sources due to the increased intensity of sulfur dioxide, black carbon, and metals.[142] This has real world consequences for SRP's customers and for the people of Arizona in general. A study from George Mason University, the Harvard School of Public Health, and UT Austin found that for every 1 $\mu g/m^3$ increase in coal particulate matter, mortality increased by 1.12%. The researchers estimated that "between 1999 and 2020, 460,000 deaths would not have occurred in the absence of emission from the coal power plants." While there are certainly customers at SRP who wish to support SRP's efforts to decarbonize, it is highly unlikely that they would do so at the risk of their own health and safety.

Similarly, any company that sells or relies on junk carbon offsets to meet carbon goals is at risk of legal action to verify its claims. In May 2023, a class-action lawsuit was filed against Delta Air Lines arguing that the airline misrepresented its carbon neutrality because of its use of junk carbon credits.[143] The lawsuit fits into a growing trend. Between 2015 and 2022, 81 "climate washing" cases were filed globally against companies. Nearly three-quarters of the 2,340 climate lawsuits that have

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[140] Jacobson *supra* note 98, at 3569.
[141] Doctrow, *Deaths associated with pollution from coal power plants*, NATIONAL INSTITUTES OF HEALTH (Dec. 12, 2024), https://www.nih.gov/news-events/nih-research-matters/deaths-associated-pollution-coal-power-plants#:~:text=Coal%2Dburning%20power%20plants%20are,%2C%20mortality%20increased%20by%201.12%25.
[142] *Id*.
[143] Greenfield, *Delta Air Lines faces lawsuit over $1bn carbon neutrality claim*, THE GUARDIAN (May 2023), https://www.theguardian.com/environment/2023/may/30/delta-air-lines-lawsuit-carbon-neutrality-aoe.

been filed since the mid-1980s have been filed in the US.[144] In this way, SRP could be at risk for selling a product to its customers that does not provide the advertised benefits, whether that is the sale of a Carbon Reduction Rider credit, or the asserted emissions reductions that SRP might claim for its own system from offsets or CCS.

WRA respectfully requests that the Board avoid the risk of using customers funds dedicated to decarbonizing programs that will fail to impact SRP's emissions in a meaningful way by rejecting the proposed Carbon Reduction Rider.

VI. Exploring Data Center Load Growth and Residential Customer Costs

WRA is encouraged by the TOU tariffs proposed for large data center customers in SRP's Proposed Adjustments. Such tariff designs can help to mitigate technical, environmental, and equity impacts of significant load growth by one group of new customers.

In the context of a process revising cost allocation and rate designs for utility customers, it is useful to consider the drivers of costs. The Proposed Adjustments identify several drivers, including some that are external, such as inflation and supply chain disruptions.[145] It also identifies investments that have been made to replace old infrastructure, technologies to improve services,[146] and major investments to support new large loads.[147] But overall, a major driver for recent and future increasing costs is load growth. One major concern for SRP's system is the large amount of load growth that is forecast to come online in the coming years. A similar trend has also been identified by SRP's neighboring electric utility Arizona Public Service in its most recent Integrated Resource Plan.[148] Regarding its own load forecast, SRP noted in its Proposed Adjustments that new large customer electricity load growth will dwarf and overwhelm the more gradual trend of residential energy use:

> Historically, SRP load growth has followed population and housing growth. However, SRP is increasingly seeing current and expected future

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[144] Rives, *Companies face 'massive growth' in litigation over climate claims*, S&P GLOBAL (July 6, 2023), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/companies-face-massive-growth-in-litigation-over-climate-claims-76429935.
[145] *Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle* at 1.
[146] *Id*. at 20.
[147] *Id*. at 16-18.
[148] *2023 Integrated Resource Plan*, ARIZONA PUBLIC SERVICE 19, https://docket.images.azcc.gov/E000031965.pdf?i=1737423861334.

> commercial and industrial business to gain a greater share of load growth. Specifically, Residential load growth is expected to grow almost 8% from Fiscal Year 2025 to Fiscal Year 2030 while Commercial and Large Industrial load is expected to grow more than 50% over the same period.[149]

With such a large amount of commercial and large industrial load growth expected over the next five years, it is important to ensure that there are protections in place to prevent cost shifting from large energy users onto residential ratepayers. Data centers in particular are geographically concentrated and inflexible large loads that provide very little benefit and require large amounts of electricity and water, while providing limited jobs to the surrounding community. The profile of these users is a high load factor and uninterruptible load, which fits well into the old power generation paradigm where large fossil fuel power plants were used for baseload. That paradigm is changing, and with the price advantage of using renewable resources over coal and fossil gas, high load factor and uninterruptible loads no longer match the most beneficial forms of generation, and therefore substantially increase system costs.

Management has a strong proposal which includes five large general service price plans (E-61, E-63, E-65, E-66, and E-67) which each use TOU rates to send time-based and load-mitigating price signals to these types of customers.[150] This is an important step to incentivizing large users to capture many of the same benefits mentioned above in WRA's E-28 comments. However, due to the significant difference in growth rate of commercial and large industrial demand when compared with residential ratepayers, as well as the time delay between pricing processes, there is a real risk of shifting cost from large users onto residential ratepayers. Serving these large customers can require large investments to establish service, including substations, generation, transmission, and power purchase contracts.

There is an important difference between cost allocation and rate design. Cost allocation and rate design are different steps in SRP's Pricing Process and serve different functions. Good rate designs include price signals to enable customers to adjust energy use in ways that reduce future costs, and to signal cost drivers on the system to the customer. Rate designs are "revenue neutral," which means they should not change the allocation of costs across classes. But prior to the rate design step, the utility calculates and apportions costs to different customer classes based on a Cost Allocation

[149] *Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle* at 4.
[150] *Id*. at 137-158.

Study.[151] The methodology to allocate costs across customer classes is important to ensure fair application of cost burdens and may need to change over time as the energy system evolves and new cost drivers emerge. Cost allocation should avoid introducing cross subsidies, with residential customers paying for costs incurred to the system to address high load factor growth from other sectors. Recently, cost allocation has tended to shift to residential customer classes due to system-wide adoption of solar energy,[152] which pushes net peak load of renewable energy later in the day while providing cheap or even free energy at times that previously were peak hours. This trend in "net peak" shift is not due to changes in residential load but rather is due to system resource and operational changes. The effects of these system and operational changes due to new energy sources should not translate into a cost allocation calculation that overly burdens residential customers.

There are ways to mitigate this risk. More frequent adjustments to rates, through a Pricing Process with updated cost allocation, is one way to help to ensure that SRP's cost allocation is up-to-date for each of its customer segments. Special contracts for new large users who require large amounts of power may also help to reduce this risk, if those contracts properly allocate costs of system upgrades, power quality enhancements, and generation resources required to serve specialized large loads. However, special contracts are often confidential and negotiated individually, so that the equitable allocation of costs may not be transparent. Management mentions in the E-67 rate that, "Pricing for these facilities is defined by customer-specific contracts," but lacking any significant detail, it is difficult to say whether this is a step in the right direction.

Additionally, SRP could consider updating its cost allocation methodology. SRP previously relied on the 4CP method, which allocates costs according to the share of energy used by each customer class during just four "critical peak" hours of the year.[153] This historical cost allocation method was based on the theory that new system costs are only driven by peak load hours. The Cost Allocation Study ("CAS") provided with the Proposed Adjustments explains that a new methodology was used to allocate costs to customer classes for the new proposed tariffs. Instead of focusing on just 4 peak hours in a year to determine cost causation and cost allocation, the new peak and average methodology considers more hours of the year in its supporting analysis but adds in the concept of "Loss of Load" probability studies

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[151] Lazar, et al., *Electric Cost Allocation for a New Era*, Regulatory Assistance Project 28 (Jan. 2, 2020), https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/.
[152] *Cost Allocation Study in Support of Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle* at 68.
[153] *Id*. at 4.

applied to the "net peak," which shift the determination of cost allocation to focus on late evening and afternoon hours.[154] It is not surprising that a "decrease in solar resource availability late in the afternoon and evening," and the availability of abundant solar energy during daytime hours may be driving a need for new generation capacity later in the evening.[155] However, this approach may shift costs onto the residential customer class, due to their typical use of energy in the evening, despite the fact that the residential customer class has had relatively flat load growth in SRP's territory. The trend of "net load" requiring new generation resources later in the evening is due to the evolution of generation resources on the grid—it is not a cost caused by residential class load growth. SRP could review alternative cost allocation methodologies that incorporate more hours than the traditional 4CP method in the CAS to better capture other cost drivers. WRA recommends the Board advise Management to explore and propose alternative cost allocation methods in its next Pricing Process. The focus should remain on cost management, rate design, fair cost allocation methodologies, and a transparent and rigorous pricing review process.

VII. Conclusion

In conclusion, WRA respectfully requests that the Board adopt the following recommendations:

1. **WRA recommends that rather than moving EZ-3 customers into the E-23 plan, these EZ-3 customers should be moved into the E-28 plan, which is also a TOU plan.**

2. **WRA recommends that Management increase the price differentiation between on-peak and off-peak rates which could better help incentivize optimal behaviors for those who do not have the option to charge during the day.**

3. **WRA recommends that SRP also develop managed charging programs in the future which can dynamically adjust EV charging in response to actual grid conditions.**

4. **WRA Recommends that SRP build upon the existing Price Principles in place by adding Sustainability to guide future pricing processes.**

[154] *Id*. at 37.
[155] *Id*. at 4.

5. **WRA recommends that the Board require Management to provide greater detail about SRP's possible use of ZECs and any other energy attribute rider.**

6. **WRA respectfully requests that the Board avoid the risk of using customers funds dedicated to decarbonizing programs that will fail to impact SRP's emissions in a meaningful way by rejecting the proposed Carbon Reduction Rider**

7. **WRA recommends the Board advise Management to explore and propose alternative cost allocation methods in its next Pricing Process to address the risks of transferring the costs of Data Center Growth to Residential Customers.**

We appreciate the opportunity to provide these comments.

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Institute for Energy Economics and Financial Analysis

CCS For Power Yet to Stack Up Against Alternatives

Recent energy price inflation may force governments to rethink their support for CCS, adding to financing risks

Michael Salt, Guest Contributor
Christina Ng, Research and Stakeholder Engagement Leader, Debt Markets

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Key Findings

The cost of carbon capture and storage (CCS) remains unclear as no known new power plants have been built with the technology installed and operating at commercial scale.

Thermal power generation with CCS has a levelized cost of electricity of at least 1.5-2 times above current alternatives, such as renewable energy plus storage.

If CCS is applied with all costs borne by increasing electricity prices, annual volume weighted average wholesale prices could climb by 95% to 175% in Australia.

Optimism bias is rampant, favoring CCS as a decarbonization and "sustainable" solution in the power sector, but who ends up paying for it is an uncertainty adding to the financing risk.

Executive Summary

The prospects for carbon capture and storage (CCS) in the power sector are far from certain.

Not only is it unable to consistently deliver on performance claims, expensive to build and fraught with failures, but the impact on electricity prices if the cost is passed through to consumers would be unsustainable.

> **The impact on electricity prices if the cost is passed through to consumers would be unsustainable.**

Despite these challenges, CCS has been marketed as a decarbonization and "sustainable" solution in the power sector, to the extent that it has made its way into policymaking discussions. For example, green or sustainable finance taxonomies recognize fossil-fired power plants as "sustainable" investments if emissions meet a specified threshold, implying a need for CCS.

The issue is that CCS for fossil-generated plants would not be sustainable if consumers cannot afford electricity. This report takes a closer look into the economic case for CCS in the power sector. A summary of our findings is as follows:

The cost trajectory for CCS remains unclear. No known new power plants have been built with CCS installed and operating at commercial scale. While two major retrofit power projects have been implemented, one has since suspended operation and both projects had performed well below target capture rates of 90%.

Yet, optimism bias is rampant. Proponents of CCS provide low cost forecasts that are a long way from the estimates of prominent organizations and significantly more optimistic than the likely reality. Additionally, estimates generally do not include a range of other costs including transport, storage, monitoring and possible remediation or penalties, which have a high degree of variability, and so they only paint part of the picture of carbon capture expenses.

In addition to cost uncertainties, how the expenses would be recovered is an added ambiguity. Our analysis shows that if CCS is applied with all costs borne by increasing the electricity price, then annual volume weighted average wholesale prices could increase by 95% to 175% in Australia. If the hike in wholesale prices is passed on, consumers are unlikely to take well to increasing electricity prices to fund CCS in the power sector. Retail electricity prices have already significantly climbed due to recent global energy inflation, resulting in pressure on the budgets of households, particularly those on low incomes, and are expected to rise further due to ongoing supply chain and geopolitical issues.

Our analysis also shows that the levelized cost of electricity (LCOE) for power generation with CCS is at least 1.5-2 times above current alternatives, which include renewable energy plus storage. Additionally, although solar and wind LCOEs have recently crept up, they are expected to return to

the downward trajectory.[1] Battery storage system prices and the resultant LCOEs will also likely improve dramatically as technology is deployed more widely at a much larger scale and is expected to displace gas-fired firming in the longer term.

Any significant government spending on or subsidization of less economically efficient technologies, including CCS, would ultimately be borne by the public through, for example, income taxes. However, this seems to contradict the need for government to use public funds responsibly in light of more technically sound options and the economical, rapidly improving and deflationary nature of renewable and battery storage alternatives.

Until a viable source of funding is available, who ends up paying for the cost of CCS in power generation is yet another uncertainty adding to the financing risk.

[1] BloombergNEF (BNEF), 1H 2022 LCOE Update, Brandily & Vasdev, 30 Jun 2022.

Introduction

Carbon capture and storage technology (CCS) directly captures carbon dioxide (CO_2) from a point source, such as a power plant or other industrial facility, then compresses, transports and stores it. Note that for CCS to qualify as a climate mitigation option, storage of CO_2 should be permanent.

CCS covers a wide variety of technologies and processes, varying levels of technical and commercial maturity, environmental and social risks and opportunities, and differing mitigation potential across a range of applications. The Institute for Energy Economics and Financial Analysis (IEEFA) previously completed a review[2] of the status and performance of the different applications of CCS.[3] This report focuses on CCS in the power sector and dives into the economics, including the impact on the cost of power and its practicalities.

Recap: Risks of CCS outweigh its benefits

IEEFA previously reported that carbon capture technologies were not yet ready to warrant them investable. A key impediment is the lack of available, and generally weak, data from the testing and operations of CCS across all applications, which makes the real technology, commercial readiness, costs and cost competitiveness uncertain.

CCS in the power sector is one of the new use cases being discussed as net-zero energy solutions, but it faces many challenges. Power plants or generators using fossil fuels, namely coal and gas, produce flue gas containing a mix of nitrogen, CO_2, water vapor, some other gases and particulate matter. CCS technologies can be designed to be built into new facilities or retrofitted at old facilities, and capture the CO_2 from flue gas, typically via chemical absorption. The CO_2 can then be transported, used and/or stored.

However, no commercial-scale new builds of these types are known to have been completed and operated, so the reality of this technology at commercial scale is untested. The Kemper CCS facility in the United States is an example of a failed attempt at deploying the technology from a new build.[4],[5] There have been two major retrofit projects, both in North America; however, one of the facilities has suspended operation and both projects had performed well below the target capture rate of 90%. China has several CCS-for-power projects that are possibly completed or being developed, but the status and configuration of these projects remain obscure.

[2] IEEFA, Carbon capture landscape 2022 – still too early to confidently fulfil promises, Salt, 7 Jul 2022.
[3] IEEFA, Investment risks of carbon capture and storage currently outweigh its potential, Salt, 7 Jul 2022.
[4] IEEFA, The carbon capture crux: Lessons learned, Robertson, 1 Sep 2022, p.44.
[5] International Energy Agency (IEA), We can't let Kemper slow the progress of carbon capture and storage, 7 Jul 2017.

Environmental concerns related to the application of CCS in the power sector have also emerged. These include:

- Fossil fuel usage: the continued use and promotion of fossil fuels through association with enhanced oil recovery conflicting with the decarbonization agenda.

- Technology effectiveness: the ability to live up to its claims as an emissions reduction strategy, given the poor performance and low capture rates to date.

- Storage risk: the uncertainty and risk around the long-term storage and leakage of CO_2.

- Energy efficiency: the consumption of additional energy to capture the CO_2 from flue gas. This results in more energy consumed and fossil fuels extracted, transported and burned when CCS is applied to generate the same amount of power.

- Chemicals used: the need for large quantities of ammonia, hydrogen sulfide and other chemical solvents, which have potential to harm the environment if a spill were to occur.

- Water usage: Power plants with CCS will require around 50% more water than non-CCS plants per megawatt (MW) of capacity.[6]

From a social perspective, operators of coal and gas power generation assets have traditionally benefited from government subsidies and protectionist policies to maintain their market position. They have also often danced around environmental and social responsibilities and regulations. As such, CCS for power generation will likely face organized public opposition and tougher environmental regulations.

Based on these findings, IEEFA concludes that the technology is not technically nor commercially ready for deployment.

IEEFA's July 2022 report[7] covers the issues mentioned above in more detail.

[6] Ibid.

[7] IEEFA, Investment risks of carbon capture and storage currently outweigh its potential, Salt, 7 Jul 2022.

Costs of Carbon Capture

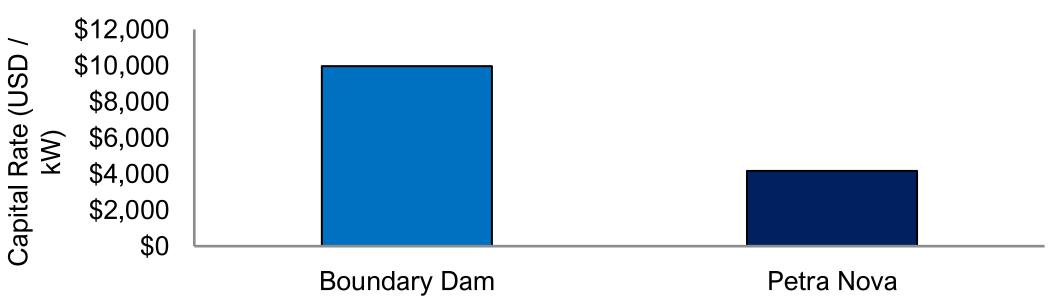
There are a range of unique technical, commercial, social and environmental costs to consider within each application of CCS.[8] S&P Global[9] analysis has shown that processes with dilute CO_2 concentrations, such as power generation, will have different cost drivers and risks than higher concentration processes such as ethanol and fertilizer production. For CCS in power, capital and operational expenditure will likely have the greatest impact on the actual cost of abating emissions.[10] The range of increased costs is explored in the following sections.

Increased Capital Expenditure

Applying carbon capture technology to coal and gas generation will significantly increase facility capital costs even without considering the required CO_2 transport and storage costs, and will affect the case for investment in the technology. A wide range of theoretical values are being discussed in the public domain for the capital required to apply carbon capture technology to coal and gas generators. However, with only two retrofitted facilities available to compare the actual costs, the real capital costs of the technology in the long run are very uncertain.

The two major carbon capture power projects, Boundary Dam in Canada and Petra Nova in the U.S., were both retrofitted with carbon capture technology and both have faced significant performance and cost challenges.[11] The capital cost in U.S. dollars per kilowatt (kW) capacity for these two projects is shown in Figure 1.

Figure 1: Capital Cost (US$/kW) for Commercial CCS Projects, Both Retrofits



Source: IEEFA analysis of various sources[12]

The capital costs of the two retrofit projects vary greatly, which in part could be down to the scale of the projects, the Boundary Dam being 115MW and Petra Nova, 240MW. Or this could just be due to

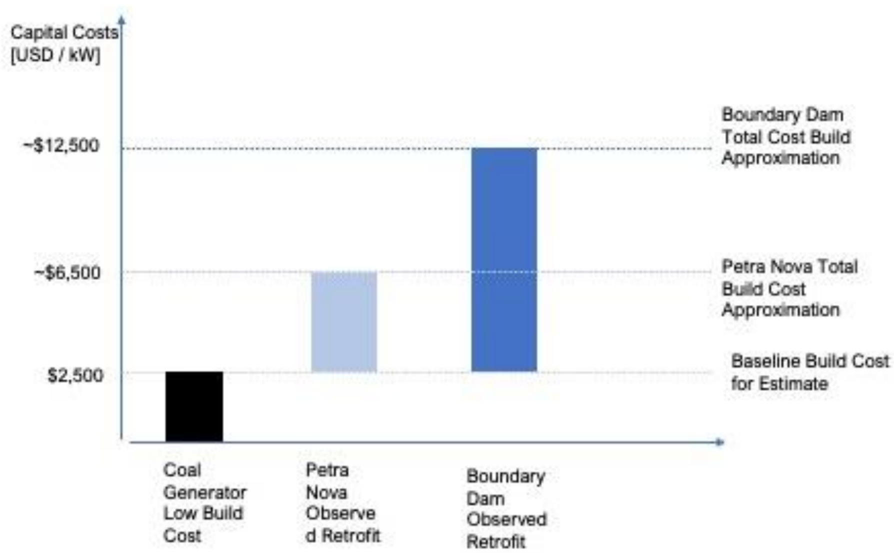
[8] Ibid.
[9] S&P Global, Levelized cost of CO2 avoided (LCCA) for CCUS projects - Cost drivers and long-term cost outlooks, 3 May 2022.
[10] Ibid.
[11] IEEFA, Two years behind schedule, Boundary Dam 3 coal plant achieves goal of capturing 4 million metric tons of CO2, Schlissel, Apr 2021, p.1-3.
[12] Massachusetts Institute of Technology (MIT), Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project, 30 Sep 2016.
MIT, Petra Nova W.A. Parish Fact Sheet: Carbon Dioxide Capture and Storage Project, 30 Sep 2016.

uncertainties in the technology, as the smaller Boundary Dam CCS retrofit costs around US$150 million more than the larger Petra Nova facility.

The cost to retrofit these projects comes on top of the underlying costs required for the base build of the coal generator. Costs to construct coal generators are currently estimated at US$2,500 to US$3,000/kW.[13] The total facility cost with carbon capture is therefore above these levels and is more than double the base build cost based on the observed cost of retrofitting.

The base build cost for a new project with carbon capture could be loosely gauged from a low benchmark of coal plant construction costs, at the rate of US$2,500/kW, plus the observed retrofit costs. Note that there should be some construction cost efficiency as a new build; however, this cannot be properly understood in the absence of an actual CCS new build. This approach is demonstrated in Figure 2 below.

Figure 2: Estimated Capital Costs of Total Facility Capital Rate (USD/kW)



Source: IEEFA analysis of various sources[14]
Note: This methodology does not consider the possible cost efficiency of a direct new coal plant build with CCS.

This approximation demonstrates that carbon capture technology significantly increases the total capital invested in the facility and is also highly variable with little justification provided. In a 2017 paper, the Global CCS Institute argued that critics had unfairly looked at unexpected plant refurbishment costs at the Boundary Dam during its start-up phase as representative of carbon

[13] Lazard, Lazard's Levelized Cost of Energy v15, Oct 2021, & Australian Energy Market Operator (AEMO), 2022 ISP: 2022 Forecasting Assumptions Update, 2022.
[14] MIT, Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project, 30 Sep 2016, MIT, Petra Nova W.A. Parish Fact Sheet: Carbon Dioxide Capture and Storage Project, 30 Sep 2016, Lazard, Lazard's Levelized Cost of Energy v15, Oct 2021; & AEMO, 2022 ISP: 2022 Forecasting Assumptions Update, 2022.

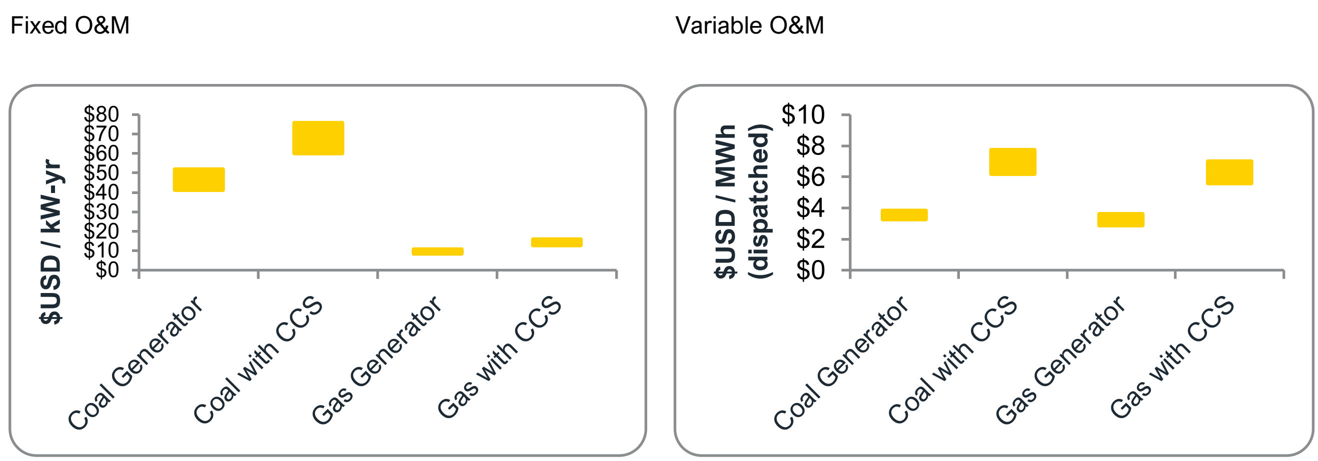
capture retrofit costs.[15] The author also described Petra Nova as having been developed without controversy;[16] however, IEEFA previously reported on cost and performance issues at the facility before it was mothballed in 2020 due to a lack of economy resulting from factors such as low oil prices.[17] What is clear is that adding carbon capture technology will significantly increase capital costs, which must be recovered through some mechanism.

Increased Operating Costs

Applying carbon capture technology, even before considering transport and storage, will raise operating costs. It will increase the use of water and fuel, and require additional facility maintenance costs through extra plant demands and usage.[18] For example, power plants with carbon capture will consume around 50% more water than non-CCS plants per MW of capacity.[19]

As such, facilities with carbon capture will face additional operating costs. The fixed and variable operating and maintenance (O&M) costs for generators without and with carbon capture are presented in Figure 3.

Figure 3: O&M Cost Increases for Power Generators with Carbon Capture



Source: IEEFA analysis of AEMO data[20]

Fixed O&M costs are expected to rise by about 45% and variable O&M costs by 95%, which again must be recovered through some mechanism.

[15] Global CCS Institute, Global Costs of Carbon Capture and Storage: 2017 Update, Irlam, Jun 2017.
[16] Ibid.
[17] IEEFA, Petra Nova Mothballing Post-Mortem: Closure of Texas Carbon Capture Plant is a Warning Sign, 3 Aug 2020.
[18] National Energy Technology Laboratory, Bituminous Coal and Natural Gas to Electricity: >90% Capture Cases Technical Note, Shultz, 30 Dec 2021.
[19] Ibid.
[20] AEMO, Current inputs, assumptions and scenarios, 2022.

Increased Fuel Costs

Carbon capture technology also requires additional energy to drive the capture of CO_2 from the flue gas. The capture technology alone is expected to consume up to 20% to 30% of the power generated, resulting in a net efficiency reduction of 6 to 12 percentage points.[21],[22] This means more fossil fuel will need to be extracted, transported and burned for a CCS-equipped system to generate the same amount of power.

Given parabolic global energy price inflation in 2021-22, use of the additional energy would inflict a severe cost penalty on carbon capture technology alone.

Figure 4: Soaring Fuel Price Inflation

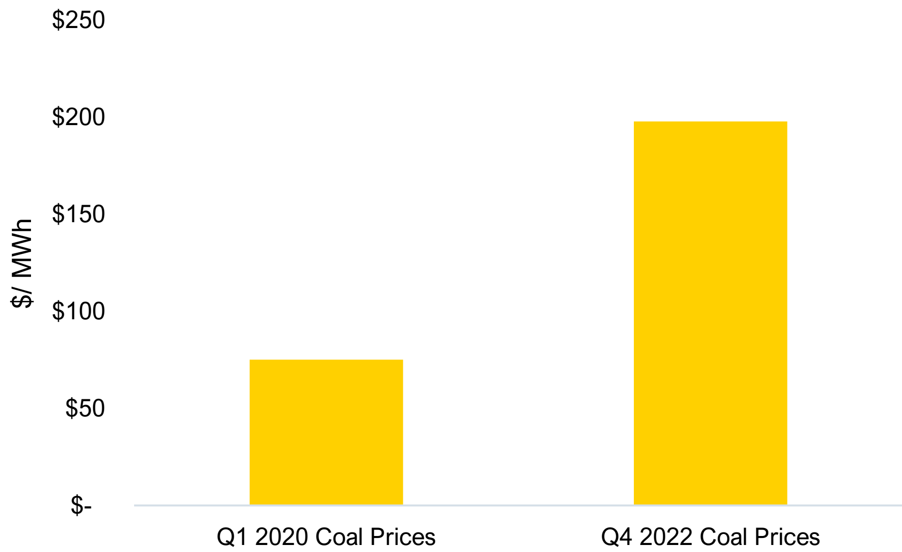
Source: Trading Economics: Newcastle coal futures[23]

Source: FRED: Global price of LNG, Asia[24]

The difference between historic and current energy commodity prices is driving the dispatch prices of thermal generators to unprecedented levels in markets where energy is priced at marginal thermal generator prices. The LCOE for coal facilities without carbon capture is estimated at historical (Jan 2020) and current (Nov 2022) prices in Figure 5.

[21] National Energy Technology Laboratory, Bituminous Coal and Natural Gas to Electricity: >90% Capture Cases Technical Note, Shultz, 30 Dec 2021, p.4.
[22] IEEFA, Carbon Capture in the Southeast Asian Market Context, Adhiguna, Apr 2022, p.34.
[23] Trading Economics, Newcastle Coal Futures, 13 Jan 2023.
[24] Federal Reserve Bank of St. Louis, Global price of LNG, Asia, 29 Sep 2022.

Figure 5: LCOE of Coal Power with no CCS



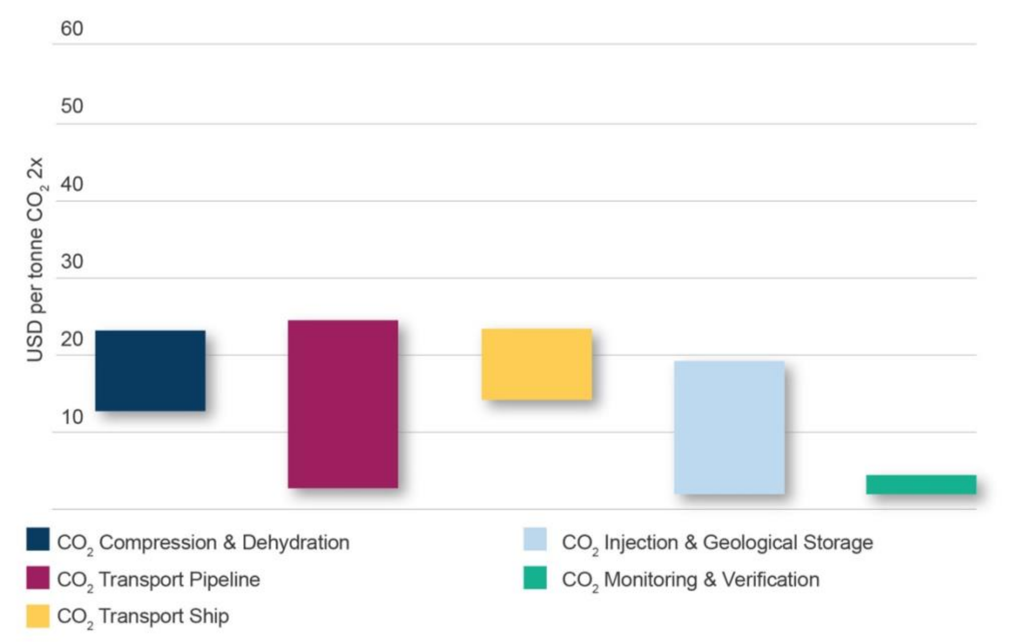
Source: IEEFA analysis
Note: This LCOE analysis assumes commodity prices are sustained at the observed levels for the stated quarter.

Increased fuel prices alone are driving up the costs of coal-powered electricity generation with carbon capture costs yet to be factored in. The same effect is observed for gas generators without carbon capture. Carbon capture technology will further exacerbate the electricity price increases from higher fuel prices.

Increased Costs Beyond the Capture Facility

The cost of CCS as a decarbonization option is more than just the cost of the carbon capture technology. The transport, storage, monitoring and verification, plus any additional compliance and liability costs will need to be taken into account for CCS to be considered as a climate solution. The additional elements of the CCS value chain are presented in Figure 6.

Figure 6: Indicative Costs for CCS Value Chain Components



Source: Global CCS Institute[25]

Transport costs are expected to vary between US$1 and US$25 per tonne of carbon dioxide (t-CO_2).[26] With cost proportional to distance, and if the transport is offshore, costs are expected to be around 15% higher.[27]

Storage costs are sensitive to whether the storage is onshore or offshore, and to the characteristics of the storage site, with saline aquifers estimated to be 10% to 15% more expensive than depleted oil and gas fields.[28] The costs are expected to vary widely based upon field capacity and well injectivity, and to a lesser degree on uncertainty in cost elements.[29] The estimated range is between US$1 and US$15/t-CO_2.[30,31]

The longevity and credibility of CO_2 storage will also depend on monitoring and verification practices, likely to be set by local regulations. Theoretical estimates suggest that the costs will probably be low

[25] Global CCS Institute, Technology Readiness and Costs of CCS, Kearns, Liu & Consoli, Mar 2021.
[26] The Royal Society, Total cost of carbon capture and storage implemented at a regional scale: northeastern and midwestern United States, Schmelz, Hochman & Miller, 14 Aug 2020, p.4-6.
[27] McKinsey & Company, Carbon Capture & Storage: Assessing the Economics, 2008, p.27.
[28] Ibid.
[29] European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), The Costs of CO2 Storage: Post-demonstration CCS in the EU, 2011, p.6.
[30] Global CCS Institute, Technology Readiness and Costs of CCS, Kearns, Liu & Consoli, Mar 2021.
[31] The Royal Society, Total cost of carbon capture and storage implemented at a regional scale: northeastern and midwestern United States, Schmelz, Hochman & Miller, 14 Aug 2020, p.4-6.

compared with other components of the supply chain.[32] However, as with other cost estimates for the technology, monitoring and verification costs are also uncertain.

Outside of the CCS value chain, compliance and liability costs also need to be provided for. These should provide coverage for risks of leakage or failure to reach abatement targets. As an example of the scale of costs, the Gorgon CCS project recently agreed to acquire and surrender US$100 million to US$184 million of credible greenhouse gas offsets recognized by the West Australian government to offset its target shortfall of CO_2 capture.[33] Appropriate liability and insurance will be required to help mitigate these cost risks.

Legal and regulatory frameworks to transfer liabilities to the state after an acceptable period post-closure and subject to performance requirements[34] may help to reduce the liability exposure for project owners; however, this approach simply transfers the risk and potential costs to future taxpayers.[35] "Claw-back" provisions that allow the state to recover costs from operators found to be at fault[36] could prove useless if the errant company is no longer in operation.

The topic of liability continues to be a critical issue for developers, policymakers and regulators in deploying carbon capture and storage.[37]

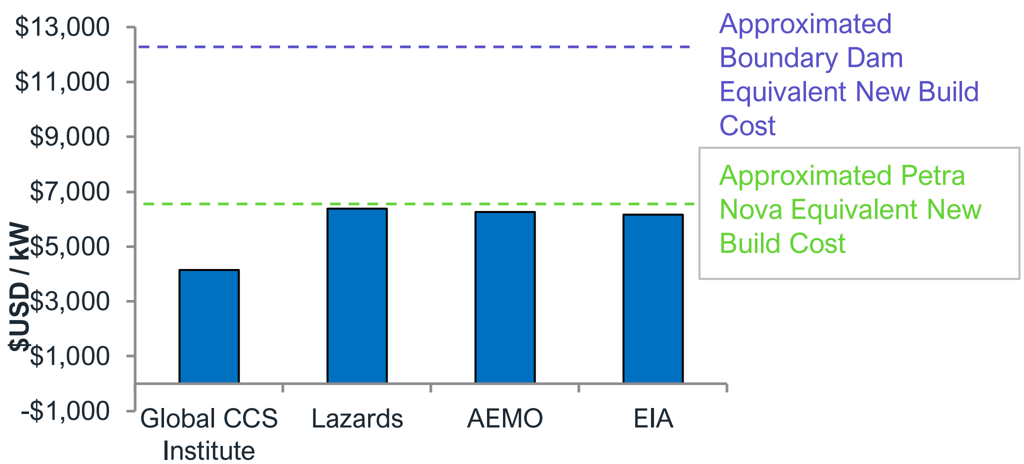
Costs in Practice Much Higher Than Estimated

Estimated benchmarks for CCS are provided on a new-build basis, yet no new CCS builds are available for comparison. Additionally, the estimates generally exclude transport and storage, likely due to the large variability of these costs, so they give only a part of the picture of carbon capture costs.

Figure 7 shows the range of cost estimates available for thermal generators with carbon capture alone, against the approximated costs of the actual major projects.

[32] Global CCS Institute, Technology Readiness and Costs of CCS, Kearns, Liu & Consoli, Mar 2021.
[33] IEEFA, Gorgon carbon capture and storage: the sting in the tail, Robertson & Mousavian, Apr 2022, p.1-2.
[34] Global CCS Institute, Unlocking Private Finance to Support CCS Investments, 2021, p.9.
[35] NOAH: Friends of the Earth Denmark, Information about Carbon Capture and Storage - CCS, Aug 2014.
[36] Global CCS Institute, Legal Liability and Carbon Capture and Storage, Havercroft and Macrory, Oct 2014, p.5.
[37] Global CCS Institute, Lessons and Perceptions: Adopting a Commercial Approach to CCS Liability, Havercroft, 2019, p.4.

Figure 7: Capital Cost Estimates for Carbon Capture Without Transport, Storage or Other Costs



Source: IEEFA analysis from various sources[38]

The approximated total build costs presented for the Boundary Dam and Petra Nova are base build costs without CCS, plus the reported retrofit costs. However, it is unclear whether the reported costs from the Boundary Dam and Petra Nova include transport and storage.

IEEFA observes that the actual plant costs for new builds would likely be above or at the upper range of current plant cost estimates made by a range of actors, including the Global CCS Institute, Lazard, the Australian Energy Market Operator (AEMO) and the U.S. Energy Information Administration (EIA).

The Global CCS Institute's estimate of CCS costs is a long way from the estimates of other prominent organizations, and a long way from the likely reality. Proponents of CCS are hopeful that learning effects come into play that would reduce costs over time through innovation and efficiency improvements.[39] However, the expected costs of CCS have increased from early estimates of around US$2,900/kW (in 2022 terms[40]) in 2007[41] to more recent estimates of around US$4,150/kW[42] (in 2022 terms[43]) in 2017. This shows a trend toward increasing costs rather than the expected decrease over time. With limited practical experience, the actual costs of currently deploying CCS and its cost trajectory remain uncertain.

[38] Global CCS Institute, Global Costs of Carbon Capture and Storage, Jun 2017.
Lazard, Lazard's Levelized Cost of Energy Analysis v15, Oct 2021;
AEMO, ISP: 2022 Forecasting Assumptions Update, 2022; &
EIA. Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies, Feb 2020.
[39] S&P Global, Levelized cost of CO2 avoided (LCCA) for CCUS projects - Cost drivers and long-term cost outlooks, 3 May 2022.
[40] Assuming 2.5% average annual inflation
[41] IEA Greenhouse Gas Research and Development Program, Capturing CO2, May 2007.
[42] Global CCS Institute, Global Costs of Carbon Capture and Storage: 2017 Update, Irlam, Jun 2017.
[43] Assuming 2.5% average annual inflation.

Does CCS in Power Sector Make Economic Sense?

While the real cost of applying CCS in the power sector is uncertain, this report considers how it could be recovered. The likely scenarios are:

- To embed the cost in increased wholesale electricity prices, which would be passed through to retailers and then consumers; or
- For the government to subsidize or find alternative sources of funding to bear the cost of CCS.

Impact on Price of Electricity: Australia Case Study

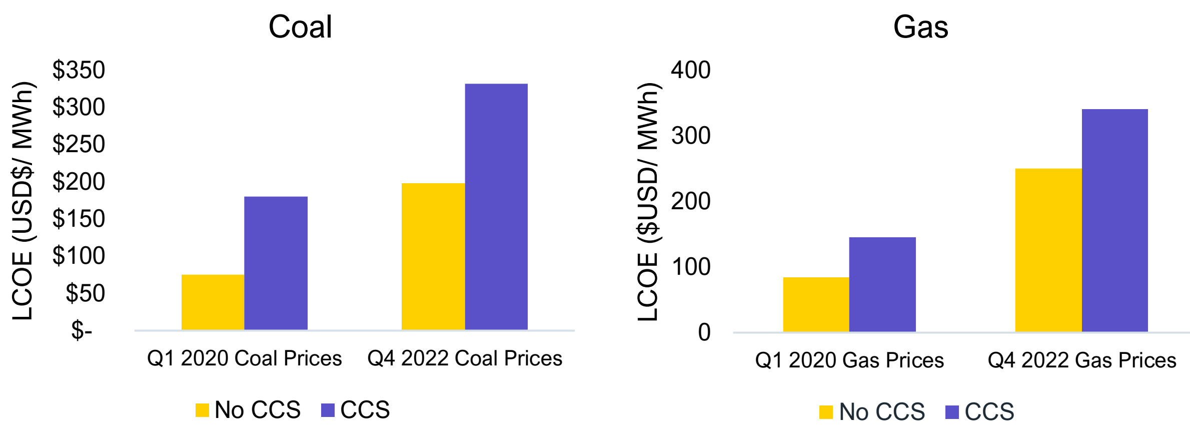
Australia's National Electricity Market (NEM) serves the east coast and major population centers, covering around 9 million customers. It consists of generators, network operators, retailers and consumers. Electricity is traded in a virtual pool to match supply with demand and set traded prices. The four largest privately owned "gentailers," being both generators and retailers, have traditionally dominated the share of customers, accounting for more than half the retail load.[44] These large "gentailers" own a big number of thermal generators; however, they are expecting the closure of many of the coal assets by the 2030s.[45]

The price of electricity in Australia is dependent on the LCOE for coal and gas generation. To understand the potential impact of adding CCS to the country's power market on electricity prices, we analyzed the LCOE for coal and gas generation with CCS application.

The analysis uses AEMO's capital expenditure estimates for non-CCS and CCS generators. These estimates are relevant to the Australian context, are industry-reviewed and publicly available[46] and generally align with other benchmarks. A full list of assumptions for the analysis can be found in the appendix.

[44] Australian Energy Regulator (AER), State of the Energy Market. 2021.
[45] The Sydney Morning Herald, Power giants feel heat on coal closures, green energy plans, 4 Jul 2022.
[46] AEMO, Current inputs, assumptions and scenarios, 2022.

Figure 8: LCOE of Historic and Current Facilities With and Without CCS



Source: IEEFA analysis (see Appendix for assumptions)

Our analysis found that, if CCS was applied with all costs borne by increasing the electricity price, then the LCOE would likely more than double for coal and increase by 75% for gas based on the historic fuel prices of Q1 2020, as seen in Figure 8. Given the heightened fuel prices from Q4 2022, the LCOE for CCS-equipped plants will probably be around 65% more for coal and 35% more for gas than the non-CCS case.

As such, adding CCS to the power sector will likely drive up the current cost of producing energy significantly, and that will need to be borne by someone.

Affordability discussion

With thermal resources providing around 70% of power generation in Australia's NEM,[47] applying CCS to these facilities to decarbonize could be expected to increase annual volume weighted average wholesale prices. These prices averaged between A$75 and A$95 per megawatt-hour (MWh) in NEM regions over the past decade,[48] and could rise by A$100 to A$130 per MWh through the inclusion of CCS.[49] This additional wholesale cost would then likely be passed on to energy consumers and increase electricity bills.

Raising electricity bills because of CCS would come on top of unprecedented electricity price increases.[50] Retail prices have already gone up and had been expected to increase by 56% over the

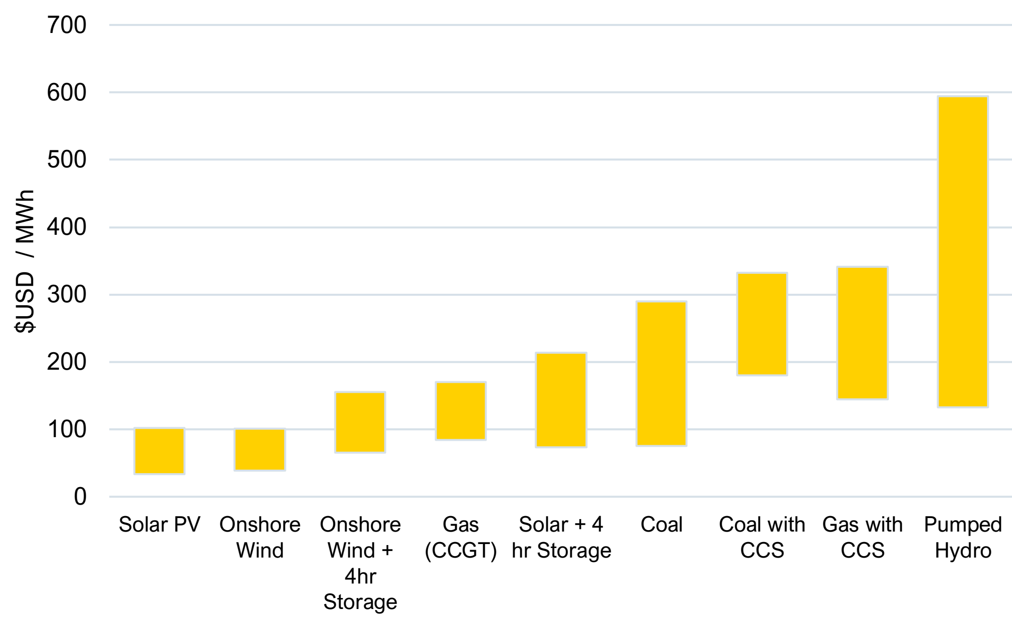
[47] Australian Energy Regulator (AER), Generation capacity and output by fuel source - NEM, 30 Sep 2022.
[48] AER, Quarterly volume weighted average spot prices – regions, 13 Jan 2023.
[49] Simply by assuming 62.5% coal (with CCS increase of +A$105-A$135/MWh) and 7.5% gas (with CCS increase of +A$60-A$90/MWh) being reflected in wholesale price increase.
[50] Australian Broadcasting Corporation (ABC) News, Russian invasion of Ukraine drives up energy costs and Australians will feel the pain, 26 Feb 2022.

next two years[51] prior to recent government intervention.[52] Any further climb in prices is expected to be taken well by neither consumers nor the government.

Consumers, businesses, industry and retailers alike would logically seek out the most affordable electricity options that meet their needs, a greater priority than environmental and social factors.

Based on new estimates (Figure 9), LCOEs for thermal power generation with CCS are at least 1.5-2 times above current alternatives, which include renewable energy plus storage. It is therefore difficult to contemplate electricity users willing to support the use of CCS on power generation when affordable decarbonized options exist.

Figure 9: Comparison of Energy Resources' LCOEs



Source: IEEFA analysis,[53] BNEF[54]

Even if CCS for thermal power generation may be required as a firming generation, that would happen only when the systems reach high levels of renewable energy generation. Firming generation would have lower capacity factors and further increase the resultant LCOEs. Meanwhile, battery storage system prices are expected to improve dramatically along with the LCOEs as technology is deployed more widely at a much larger scale and expected to displace gas-fired firming. [55]

[51] The Australian Financial Review, Labor's power prices promise dead: energy costs to spike 56pc, 25 Oct 2022.
[52] ABC News, Coal and gas price caps and whether they'll lower your energy bills explained, 10 Dec 2022.
[53] IEEFA LCOE Analysis (see Appendix for input assumptions).
[54] BNEF, 1H 2022 LCOE Update, Brandily & Vsdefv, 30 Jun 2022.
[55] Ibid.

Government Support

The government could support CCS in the power sector indirectly, for example, by taxing carbon emitters or granting direct project subsidies.

A carbon pricing or emissions trading scheme would create an incentive for coal and gas generators to implement CCS to minimize costs. However, it is worth noting that CCS has been commercially demonstrated to capture only around 75% of CO_2 emissions, according to experience at Petra Nova.[56] Accordingly, even if carbon pricing were to be applied, the plant owner or operator would have to pay the price of residual emissions not captured by CCS. This additional cost of residual emissions liability will need to be funded by some mechanism.

Carbon pricing in Australia has been a political land mine. The Clean Energy Act 2011 introduced a carbon pricing mechanism, which put a price on carbon pollution and was designed to lead to an emissions trading scheme. The mechanism was used as a political weapon to attack the government at that time and was repealed in July 2014.[57] The *Safeguard Mechanism*[58] now in place is largely seen as ineffective. The prospects of a direct carbon tax or pricing scheme in the near future seem uncertain at best.

Even if the government were to reintroduce and implement a similar initiative, businesses including high emitters will likely seek out more affordable electricity alternatives, as described earlier.

An alternative form of support may be to grant direct project capital support. However, any significant government spending on or subsidization of CCS would ultimately be borne by the public through, for example, income taxes. The public may be unwilling to accept subsidizing unproven CCS technologies and, in turn, express their views through public elections.

In other markets where the government subsidizes power via reduced input costs for producers or lower prices to consumers, more government subsidies will be required to cover the full or partial cost of CCS.

Until a viable source of funding is available, who ends up paying for the cost of CCS in power generation is yet another uncertainty.

[56] IEEFA, Where's the beef? Enchant's San Juan generating station CCS retrofit remains behind schedule, financially unviable, Schlissel, May 2021, p.3.
[57] Climate Scorecard, Australia's Ill-Fated Emissions Trading System, 6 Mar 2020.
[58] The Guardian, What is the 'safeguard mechanism' and how is it supposed to reduce Australia's carbon emissions? 17 Nov 2021.

Conclusion

IEEFA previously concluded that CCS technology was struggling to fully work at scale both technically and commercially. The current report concludes that the economic case for CCS in the power sector is weak, considering input cost and funding uncertainties, continued failures of the technology, and the constantly improving and rapidly growing alternatives.

Applying carbon capture technology to coal and gas power generation, even before considering the required transport and storage of CO_2, will significantly increase the facility capital expenditure, operating and fuel costs, and affect the case for investment in the technology. There are no known new build commercial-scale projects built and operated. Of the two major retrofit projects, one has suspended operation and both had performed well below target capture rates of 90%.

Actual plant costs for new builds are expected to be at or above the upper range of current plant cost estimates made by a variety of actors. The Global CCS Institute, as one of the main global proponents of the technology, has promoted a range of cost estimates for the technology. However, these are a long way from the estimates of other prominent organizations, and a long way from the likely reality.

The actual costs of deploying CCS are uncertain and the cost trajectory remains unclear. Additionally, estimated costs generally do not include other expenses, including transport, storage and possible remediation or penalties, which have a high degree of variability, and so they paint only part of the picture of carbon capture costs.

In Australia, retail electricity prices have increased and had been expected to go up by another 56% over the next two years, prior to recent government intervention. Our analysis found that, if CCS is applied in the Australian power sector, with all costs borne by raising the electricity price, then the LCOE could increase annual volume weighted average wholesale prices by 95% to 175%. The affordability of electricity with CCS added would become an issue and is unlikely to be taken well by consumers nor government alike.

Based on our analysis, LCOEs for thermal power generation with CCS are at least 1.5-2 times above current alternatives, which include renewable energy plus storage. CCS for power generation may be required for firming gas generation. But this would happen only when the systems reach very high levels of renewable energy generation and the lower capacity factors would further increase the LCOE. Meanwhile, battery storage system prices and the resultant LCOEs are expected to improve dramatically as technology is deployed more widely at a much larger scale and is expected to displace gas-fired firming. Any significant CCS spending or subsidy from the government would ultimately be borne by the public through, for example, income taxes. The public may be unwilling to accept subsidizing unproven CCS technologies and, in turn, express their views through public elections.

However, this seems to contradict the need for government to use public funds responsibly in light of more economical and technically sound options.

Until a viable source of funding is available, who ends up paying for the cost of CCS in power generation is yet another uncertainty.

Appendix - Assumptions for Analysis

AEMO's cost estimates for CCS have been used to develop Australia's national electricity market Integrated Systems Plan (ISP). Its alignment with other prominent estimates and our approximation of capital costs also makes it a reasonable base case from which to decide on assumptions in the current analysis. We have therefore adopted the Global CCS Institute's estimates for facilities as an optimistic long-run capital case.

Table 1: Fuel Cost Assumptions

Type	Q1 2020	Q4 2022
CCS for Coal Generator[59]	$58 / t	$390 / t
CCS for Gas[60]	$6.84 / GJ	$25.21 / GJ

[59] Trading Economics, Coal, 13 Jan 2023.
[60] AER, Gas Market Prices, 13 Jan 2023.

Table 2: CCS for Power Analysis – General Assumptions

Parameter	Coal	Gas	Justification & Source
Capital cost without CCS (A$)	$4,343	$1,559	Build cost - current policies[61]
Capital cost with CCS (A$)	$9,077	$4,011	Build cost - current policies[62]
Economic life	30	25	Economic life[63]
Efficiency loss	9%	10%	Difference between non-CCS and CCS facilities' thermal efficiency[64]
Capacity factor without CCS	83%	70%	Capacity factor from low-cost case[65]
Capacity factor with CCS	66%	60%	Coal: capacity factor from coal high-cost case[66] Gas: effective annual capacity factor[67]
Capture rate	90%	90%	Optimistic capture rates are often referenced in discussions of CCS[68]
Fixed O&M without CCS (A$/kW-yr)	$46.56	$9.54	Median value from non-CCS fixed O&M (AEMO workbook)[69]
Fixed O&M with CCS (A$/kW-yr)	$67.88	$14.32	Median value from fixed O&M with CCS (AEMO workbook)[70]
Variable O&M without CCS (A$/MWh)	$3.56	$3.24	Median value from non-CCS fixed O&M (AEMO workbook)[71]
Variable O&M with CCS (A$/MWh)	$6.96	$6.31	Median value from fixed O&M with CCS (AEMO workbook)[72]
Transport and storage (US$/t-CO2)	$20		Midpoint value from Royal Society's transport and storage costs[73]
A$-US$	0.69		Average 2022 exchange rate[74]

The analysis considers the price that electricity must be sold at to recover costs and pay back investors. The levelized cost of electricity (LCOE) is a common measure of the breakeven price that electricity must sell at to recover costs and service obligations.

61 AEMO, 2022 ISP: 2022 Forecasting Assumptions Update, 2022.
62 Ibid.
63 Ibid.
64 International Journal of Greenhouse Gas Control: 57. Carbon capture and storage across fuels and sectors in energy system transformation pathways. Muratori et al. p.34-41.
65 Lazard, Lazard's Levelized Cost of Energy v15, Oct 2021.
66 Lazard, Lazard's Levelized Cost of Energy v15, Oct 2021.
67 Aurecon Group, 2021 Costs and Technical Parameter Review, 27 Oct 2021.
68 International Renewable Energy Agency, Reaching Zero with Renewables: Capturing Carbon, Lyons, Durrant & Kochhar, Oct 2021, p.14.
69 AEMO, 2022 ISP: 2022 Forecasting Assumptions Update, 2022.
70 Ibid.
71 Ibid.
72 Ibid.
73 The Royal Society, Total cost of carbon capture and storage implemented at a regional scale: northeastern and midwestern United States, Schmelz, Hochman & Miller, 14 Aug 2020, p4-6.
74 Exchange Rates UK, US Dollar to Australian Dollar Spot Exchange Rates for 2022, 13 Jan 2023.

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The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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