SELECTED ELECTRIC UTILITY TRENDS

PREPARED FOR:
SALT RIVER PROJECT

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SECTION 1:
EXECUTIVE SUMMARY

SRP management has asked Concentric Energy Advisors ("Concentric") to summarize certain recent electric utility industry trends and how peer utilities are addressing these trends. This summary addressed the following recent trends:

- Regional Electricity Prices
- Rate Adjustment Mechanisms
- Time-of-Use ("TOU") Hours
- Distributed Generation Rate Design
- Monthly Service Charges
- Data Center Rates & Cost Responsibility

Over the past decade, electric utilities have experienced relatively slow load growth in the range of less than 1% to 3%. However, recent load growth and forecasts for future load growth have begun to rise significantly, with some utilities now expecting electricity consumption to increase at annual rates in excess of 5% over the next decade.[1] This load growth is due to strong overall economic activity, a trend toward on-shoring manufacturing, growth in data centers, and greater use of heat pumps and electric vehicles. Serving this new load will require significant new investment by utilities across all aspects of utility operations.

With rising investment requirements pressuring electric rates, utilities are striving to ensure electric rates remain affordable to end use customers. While electric rates have increased over the past decade in nominal terms, when adjusted for inflation, real electric rates have declined nationally by 6% since 2014.[2] During this same time frame, electricity rates in Arizona, stated in real dollars, have declined by 6% and SRP has been able to reduce real electric rates by 13%.

One way utilities are managing the impact of new investments on customer rates is to smooth the impact of rate changes using various forms of rate adjustment mechanisms targeted at recovering specific cost elements. These rate adjustors provide regulators and utilities greater flexibility in ensuring timely cost recovery without the expense of a full pricing process or general rates case. Utilities in Arizona and large public power utilities have used rate adjustors to accelerate investment in distribution, transmission and generation assets that enhance reliability and achieve climate goals.

Another notable trend in recent years has been the significant increase in the development of solar generation, at both customer premises and at utility scale. The output of solar generation has now become so significant in certain states that there is an excess of generation during certain daylight hours, causing the price of electricity to fall during daylight hours and rise during evening

1 *See* Wood McKenzie, Gridlock: The Demand Dilemma Facing the US Power Industry, October 2024.

2 Nominal costs were converted to real dollars using the St. Lous Federal Reserve Bank, Gross Domestic Product Implicit Price Deflator (FRED GDP Deflator) available at: https://fred.stlouisfed.org/series/GDPDEF/

periods, when solar generation is not available. This fundamental change in pricing patterns has required utilities to redefine the periods designated as "peak" and "off-peak." Utilities that had traditionally used peak and off-peak periods and TOU pricing to incent customers to shift load away from midday on-peak periods are now resetting rates such that on-peak periods (i.e., high-priced periods) now occur after sunset and the off-peak periods may now occur during midday hours.

In providing electric service, utilities incur both fixed and variables costs and recover those costs from customers through customer charges, demand charges and variable energy rates. The gold standard in setting rates is to allocate costs to customers that "cause" specific costs and to collect these costs in a manner similar to how these costs were incurred by the utility (i.e., recover fixed costs through fixed rate elements and variable costs through variable rate elements). However, utilities have long deviated from this practice to simplify rates, particularly for residential customers, resulting in fixed cost recovery that mainly occurs through variable rates.

This approach was acceptable when the pattern of customer usage was similar across a rate class. However, now with many customers owning roof top solar generation, utilities are finding that they may under recover fixed costs and these costs are being shifted to customers without roof-top solar. To address this situation, utilities are using certain non-bypassable charges applicable to customers with roof-top solar or other forms of distributed generation.[3] Arizona utilities also have reduced the rates paid for electricity that customers export on to the grid to more closely reflect the actual cost of electricity at the time-of-day this excess power is generated.

As utilities seek to better align rates with costs, there is also a trend toward increasing the amount collected through the customer monthly service charge ("MSC"). The benefit of doing so is to reduce cross subsidization and in some cases address income equity issues. For example, some states have now implemented monthly service charges and minimum bill provisions for residential customers in the range of $25 per month.[4]

The significant load increases from large data centers is projected to grow between 4% and 15% annually, depending on the region through 2030. The growth in data center load has been and is expected to continue to be concentrated in Arizona, Illinois, Ohio, New York, Ohio, and Virginia. To serve this new load, utilities will likely need to make significant system investments which raises concerns that these costs may be shifted to other customers. To address this situation, utilities are seeking to develop special contracts with new data centers that provide financial assurances of cost recovery.

Each of these trends is examined in greater detail in the following sections of this document.

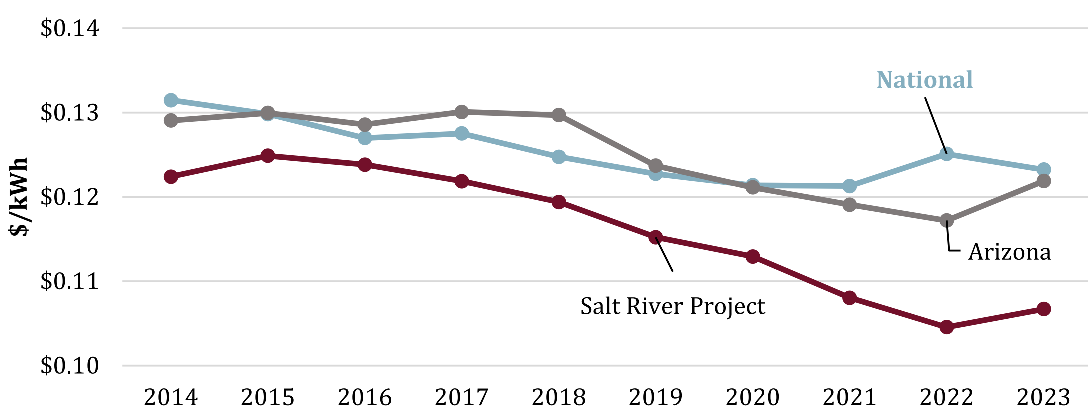
3 One example of this form of rate design is the Grid Access Charge ("GAC") implemented by Arizona Public Service ("APS").

4 Examples of this type of charge exist in California, Hawaii, Florida and other states.

SECTION 2:
REGIONAL ELECTRICITY PRICES

While electric rates have increased over the past decade in nominal terms, when adjusted for inflation, real electric rates have declined nationally by 6% since 2014 as shown in Figure 1.[5] During this same period, electricity rates in Arizona stated in real dollars have declined by 6% and SRP has been able to reduce real electric rates by 13%. This pattern is similar for residential and commercial customers. For residential customers nationally, real retail electric rates declined by 2% from 2014 through 2023. In Arizona, these rates have declined by 7%, and for SRP real retail rates declined by 13%. For commercial customers nationally, real retail electric rates declined by 11% from 2014 through 2023. In Arizona, these rates have declined by 8%, and for SRP real retail rates declined by 14%. While there are a several reasons that may explain this overall rate trend, an important driver is the reduction in wholesale natural gas prices which have declined by 54% from 2014 to 2023.

FIGURE 1: Real Retail Electricity Prices 2024 - 2023

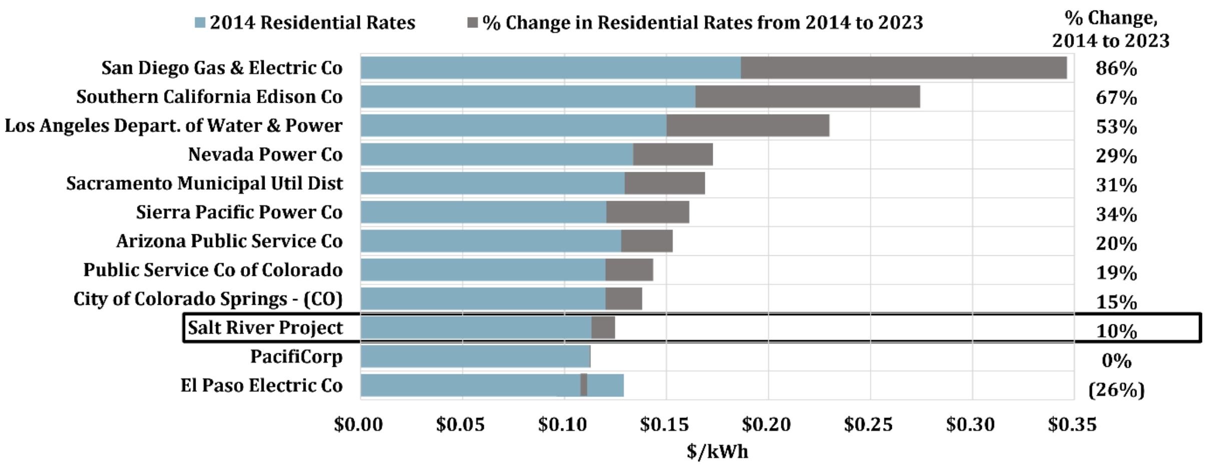


Source: Annual Electric Power Industry Report, Form EIA-861, Average bundled retail electric prices calculated as total bundled revenues divided by total bundled kWh sales, adjusted for inflation using the FRED GDP Deflator.

Despite this general trend of lower real electricity prices, recent nominal electricity rate increases in certain markets have raised significant concerns in several states, with policy makers seeking to address costs for low-income consumers (e.g., CA, NY). These cost increases are occurring due to general inflationary pressures and large infrastructure investments necessary to advance decarbonization initiatives, address reliability concerns and meet growing customer demand. However, in the face of these challenges, SRP rates have remained in the bottom quartile of Southwestern U.S utility peer group rates as shown in Figure 2, below.

5 Nominal costs adjusted for inflation using the FRED GDP Deflator.

FIGURE 2: Nominal Residential Rates Relative to Southwest Peers 2014 – 2023



SECTION 3:
RATE ADJUSTMENT MECHANISMS

Electric utilities have traditionally adjusted base rates during a periodic pricing process or rate case and passed through changes in fuel and purchased powers costs as these costs were incurred. Rate adjustors such as the fuel and purchased power adjustment clause are utility rate elements that are outside of base rates and may be required due to volatile fuel and/or purchased power prices, unanticipated expenses (resulting from changes in prices and/or quantities) or a desire to segregate certain costs. These costs or credits may remain outside of base rates indefinitely or be rolled into base rates during a subsequent pricing process.

Rate adjustors are becoming increasingly common as utilities and their regulators seek to accelerate investment in specific areas of utility operations while ensuring timely cost recovery, without the expense of a full pricing process or general rates case.

Utilities in Arizona and large public power utilities such as the Los Angeles Department of Water and Power use rate adjustors to accelerate investment in distribution, transmission and generation assets that enhance reliability and achieve climate goals. Utilities across the U.S. are now using adjustors to recover specific areas of costs as shown in Table 1 below.

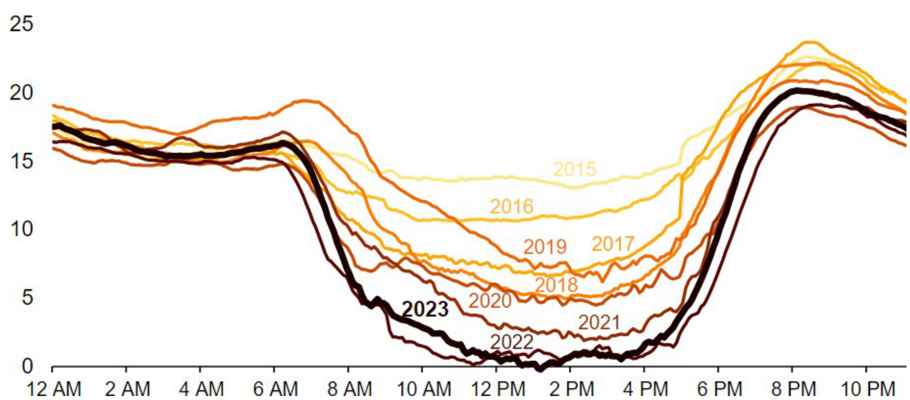
TABLE 1: Types of Rate Adjustors Commonly Used by Utilities

Adjustor Type	Description
Storm Damage Cost Recovery	Funds to cover rebuilding of the utility distribution system following extreme weather event.
Smart Meter Project	Recovers costs of smart meter installation projects.
New Capital Investment	Begins recovery of capital investments that occur between rate cases.
Special Assessment	Funds system expansion or replacement of specific facilities and reduces the rate shock of a new asset entering rate base.
Refund of Deferred Income Taxes	Provides refunds following enactment of a tax reduction.
Transmission Investment	Automatic annual updates to tariffed rates to recover new revenue requirements or to adjust for change in peak demand.

SECTION 4:
TIME OF USE HOURS

Utilities have traditionally used TOU rates to incent customers to shift load away from high load midday periods. While utility-defined peak periods varied, these time periods were generally coincident with daytime and early evening hours. With greater adoption of solar generation, the highest net load periods now often occur in the evening after the sun has set, as solar generation declines, and customer demand remains high.[6] Utilities must now reset TOU periods and rates to align with the changes in the pattern of net load. This change in load patterns was first observed in California where the new net load shape became known as the "duck curve" as shown in Figure 3, below.

FIGURE 3: California Duck Curve Net Load (GW) March to May 2015 - 2023



Source: CAISO.
https://www.eia.gov/todayinenergy/detail.php?id=56880

This figure shows how over the past 10 years, the net load trough in California has become more pronounced, to the point where the net load of the system between March and May each year is effectively zero at midday. As a result, utilities are now seeking to incent consumers to shift load to the midday periods to take advantage of excess generation and reduce load in the evenings. As a result, it is now common for utilities operating in regions with a high concentration of solar generation to have revised their on-peak period hours to occur later into the day. A similar shift in TOU hours is also underway at SRP.[7] Under these changes in TOU rate periods, utilities are also shortening the duration of the on-peak period and in some cases making TOU rates that were once optional now mandatory.

6 Net load is calculated as total electric demand less the generation from non-dispatchable generation such as wind and solar.

7 For example, SRP has proposed a residential TOU rate (E-16) which include a super off-peak period from 8 a.m. – 3 p.m. and an on-peak period from 5 p.m. – 10 p.m. All other hours are considered off-peak.

In addition to providing TOU rate incentives to shift usage away from the evening peak periods, utilities are also performing customer outreach to notify customers that TOU periods have changed. These actions are intended to accelerate the response to these price changes and avoid rate shock.[8] Certain utilities have provided commercial and industrial customers with tools to evaluate costs under various TOU options[9] and utilities are also offering bill protection for customers whose first-year bill under a new TOU rate may be higher than under a prior rate structure.[10]

8 Sacramento Municipal Utility District ("SMUD") has multiple online resources to educate customers about their TOU periods. (For additional details see: https://www.smud.org/Rate-Information/Residential-rates/Time-of-Day-5-8pm-Rate and https://www.smud.org/-/media/Documents/Rate-Information/Time-of-Day/TOD-Printable-Rate-Chart.ashx)

9 Xcel Energy provides small commercial and industrial customers with an online rate comparison tool (For additional details see: https://co.my.xcelenergy.com/s/business/rate-plans/comparison-tool).

10 Public Service Electric & Gas Long Island New York ("PSEG LINY") offers guaranteed bill protection for up to the first 12months on a new time of day ("TOD") rate where, if, during that period the total electric cost on a TOD Rate is higher than it would have been under the Flat Rate, the utility will automatically provide a bill credit to refund the difference (For additional details see: https://www.psegliny.com/timeofday).

SECTION 5:
DISTRIBUTED GENERATION RATES

In providing electric service, utilities incur both fixed and variables costs and recover those costs from customers through customer charges, demand charges and variable energy rates. The gold standard in setting rates is to allocate costs to customers that "cause" certain costs and to collect these costs in a manner similar to how these costs were incurred by the utility (i.e., recover fixed costs through fixed rate elements and variable costs through variable rate elements). However, utilities have long deviated from this practice to simplify rates, particularly for residential customers, resulting in the recovery of fixed costs largely through variable rates.

This approach was acceptable when the pattern of customer usage was similar across a rate class. However, now with many customers owning roof top solar generation, utilities are finding that they may under recover fixed costs and these costs are being shifted to customers without roof-top solar. Furthermore, utility costs have become increasingly more fixed, as renewable generation does not incur variable fuel expenses, more fixed cost transmission is required to bring renewable energy to load centers and information technology requirements increase.

To address this situation, utilities such as APS and Tucson Electric Power have been authorized by the Arizona Corporation Commission ("ACC") to implement non-bypassable charges to recover a portion of the shortfall in recovery of fixed costs incurred to serve customers with roof-top solar or other forms of distributed generation. In the case of APS, the ACC approved a Grid Access Charge ("GAC") which moved "toward rate parity," but did not fully correct the shortall in cost recovery between residential solar and non-solar customers.[11]

The ACC has also required Arizona utilities on several occasions to reduce the rate paid for electricity that customers export on to the grid, under the Resource Comparison Proxy ("RCP"). These reductions were an effort on the part of the ACC to better align rates paid to customers exporting power onto the grid with the actual market value of this electricity and thus to mitigate subsidization by customers without distributed generation. While the ACC required a reduction in the RCP, because the RCP cannot be reduced by more than 10% at any one time, the ACC found that the RCP remains above actual avoided costs.[12]

These changes in rate design seek to ensure that all customers pay an appropriate share of system costs, particularly when fixed cost recovery is overly dependent on variable electricity rates. In certain cases, utilities are seeking alternative fixed cost recovery methods that are not reliant on variable energy sales such as minimum bills.[13] However, in many cases rates continue to not fully achieve equitable cost recovery given a variety of factors.

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11 *See* ACC Decision No. 79293 in Docket No. E-01345A-22-0144 at 283-84, 448.

12 *See* ACC Decision No. 79097 in Docket No. E-01345A-23-0110.

13 See Hawaiian Electric effective rate summaries. (For additional details see : https://www.hawaiianelectric.com/documents/billing_and_payment/rates/effective_rate_summary/efs_2024_10.pdf)

Utilities have also sought to credit customers with rooftop solar through "value of solar" programs that compensate customers for the potential value(s) that solar generation can bring in terms of lower distribution investment and other cost savings. However, the role of behind the meter solar generation in deferring utility investment has been challenging to realize, as behind the meter solar generation is often deployed in a highly localized and unsystematic manner which may not permit utility planners to rely on its availability.

SECTION 6:
MONTHLY SERVICE CHARGES

Utilities are increasingly seeking to better align rate design components with cost causation, which has resulted in a trend of increased MSCs. This trend aims to reduce cross-subsidization between customer classes, address income equity issues and ensure adequate fixed cost recovery. Utilities have also introduced innovative rate design concepts such as minimum bill provisions for residential customers.

MSCs are designed to cover the portion of the utility's fixed costs associated with providing service to the customer's location and can include costs for electric meters, billing expenses and other costs that do not vary with the amount of energy provided. Utilities determine the appropriate level of MSCs through detailed cost-of-service studies, which include specific cost allocation analyses such as zero-intercept and minimum system cost analyses. Despite these efforts, final MSC rates are commonly set below the amount indicated by these studies, which can lead to a misalignment of pricing principles.

When MSCs are set too low, a portion of the utility's fixed costs must be recovered through variable rates, which can lead to cross-subsidization among customers. Since variable rates are less predictable than fixed rates, this rate structure can eventually lead to an under recovery of fixed costs. In extreme cases, an MSC that does not recover a significant portion of fixed costs can result in lower earnings stability for a utility, poorer credit metrics, and ultimately higher customer rates through increases in costs of capital.

Utilities have traditionally had a single MSC for each customer class, which may not accurately reflect the actual cost differential among customers given customer density and the differences in the capacity of service drop (e.g., 100, 200 and 400 ampere service). To address this situation, several states have moved toward higher MSCs and introduced minimum bill criteria to address these issues. For instance, California has implemented an income-graduated MSC structure with three tiers, increasing the MSC by almost 100% for customers not enrolled in energy assistance programs. Florida Power and Light has instituted a minimum bill provision to ensure that customers with little to no energy usage fairly contribute to the fixed costs incurred to serve them, setting the minimum charge at $25 per month. Similarly, California investor-owned utilities have now implemented a $24.15 per month MSC for customers not enrolled in energy assistance programs.

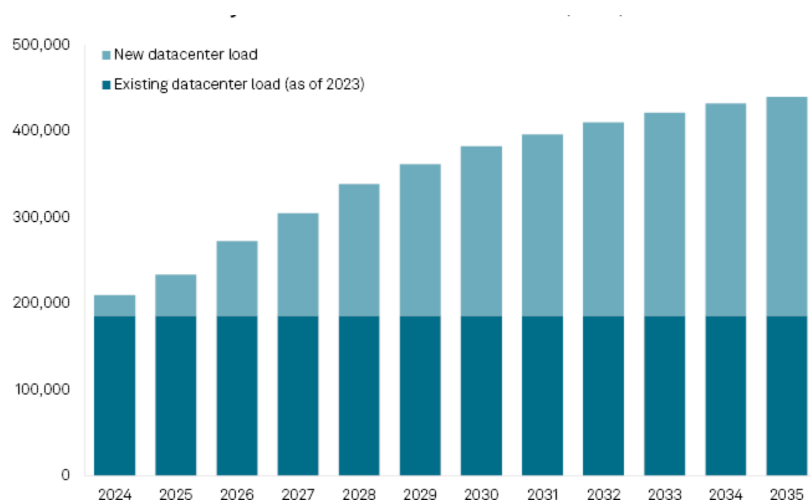
SECTION 7:

DATA CENTER RATES & COST RESPONSIBILITY

S&P Global estimates that data center energy demand could grow from 200 TWh in 2022 to over 400 TWh by 2035, as shown in Figure 4, and account for over 7.5% of total United States power demand. The growth rate is expected to be between 4% and 15% through 2030 in certain regions with the most rapid growth expected to be concentrated primarily in Arizona, Illinois, Ohio, New York, and Virginia.

To serve this new load, utilities will need to make substantial system investments to provide service to these data centers, which raises concerns over the impact on existing customers and the risk of cost recovery. To mitigate these issues, utilities are developing special contracts for entities seeking to construct data centers which provide the utility financial assurances of cost recovery.

FIGURE 4: Projected Data Center Electricity Demand 2024 through 2035



Source: S&P Global Commodity Insights.

The rapid expansion of data centers presents several challenges for the utility industry. One major issue is the need for significant infrastructure investments to support this increased load. These investments can be costly and may lead to higher rates for other customers, if not managed properly. Additionally, the concentration of data centers in specific regions can strain local network grids and require targeted upgrades, further complicating the financial and logistical aspects of these projects.

Another challenge is ensuring that the costs associated with these investments are fairly distributed. Without proper measures, there is a risk that the financial burden could be shifted to residential and small business customers, leading to potential equity issues. The need for reliable and resilient power supply for data centers also necessitates advanced planning and coordination to prevent disruptions and ensure continuous service.

To address these challenges, utilities are turning to special contracts with data center developers that provide financial assurances in the form of collateral posting and minimum bills based on contract demand levels. This collateral may be in the form of parent guarantees, cash, or letters of credit and set based on the creditworthiness of the data center owners.[14] These contract terms may also consider the magnitude of the required investment, the customers load pattern, and ways to provide data centers flexibility in managing load growth (e.g., incentives for a certain level of load growth).

These special contracts can take the form of a negotiated rate, but more commonly, these are bilateral contracts, with the data center customer subject to the same rate schedule applicable to similar-sized loads. For example, in Ohio, American Electric Power ("AEP") filed an application to establish new tariffs for data centers with terms and conditions specifically structured to enhance the certainty of cost recovery. AEP did this by requesting to establish contract terms with minimum service lengths and fees for early termination, minimum bills, and collateral provisions in the form of cash guarantees equal to 50% of the customers minimum charges calculated as of the date when the electric service agreement is signed. With respect to the rates proposed by AEP, the rates for data centers would be equal to those under AEP's General Service schedule.[15]

[14] See Ohio Public Utility Commission ("OPUC") Case No. 24-0508-EL-ATA Joint Stipulation and Recommendation at 5.

[15] As of October 10, 2024, AEP and the data center owners have developed a proposed settlement which is pending OPUC approval.