CITY OF TUCSON

Commission on Climate, Energy, and Sustainability
Thursday, June 11, 2026, 4-6pm
City Council Ward 6
3202 E 1st St
Tucson, AZ 85716

Meeting Minutes

1. Call to order/Roll call

Quorum achieved and meeting called to order by Commission Chair Stormont at 4:03pm.

Members present

Dan Stormont	Representative, City Manager, Chairperson (in-person)
Adriana Bachmann	Representative, Ward 2, Vice-Chairperson (in-person)
Garrett Weaver	Representative, City Manager (in-person)
Joseph Rocky Rivera	Representative, Ward 5 (online)
Moises Gomez	Representative, Mayor (in-person)
Natalie Shepp	Representative, Ward 6 (in-person)

Members absent

Camila Martins-Bekat	Utility Representative, City Manager
Katy Brown	Environmental Org Representative, City Manager
Ojas Sanghi	Representative, Ward 3

2. Call to the audience

Bruce Plenk, Daniel Dempsey, and Shelly Gordon made statements to the Commission.

3. Approval of minutes from previous commission meeting

Motion was made by Commissioner Weaver to approve the minutes of the May 13, 2026 meeting, duly seconded by Commissioner Bachmann, with the incorporation of corrections suggested by Chair Stormont. The motion was passed by a voice vote of 6 to 0.

4. Climate Resilience report

Energy Manager Michael Catanzaro read some notes from Chief Resilience Officer Fatima Luna because she was not available to attend the meeting.

CRO Luna's statement was that there wouldn't be any additional public outreach about the Energy Collaboration Agreement since it has already been approved by

Mayor and Council, but there will still be some work on a framework for ECA implementation and staff will socialize the plan within the bounds of what's allowable.

Members of the Commission asked some clarifying questions about plans for working on the implementation framework. CR Luna will bring an updated framework to the Commission for feedback before the election.

Commissioner Weaver asked if Mayor & Council had approved the final wording for the Franchise Agreement. EM Catanzaro wasn't sure. He will check on the status and send a note to the Commission.

No action taken.

5. Energy Manager report

Energy Manager Catanzaro updated the Commission on upgrading environmental controls for city properties and savings from solar projects implemented by the City this year.

The upgraded environmental control projects are being funded by the Green Fund approved by Mayor and Council in 2019. The pilot program has saved the City $120,000 annually. EM Catanzaro will report updates to the Commission.

Initial estimates of savings from solar power agreements should be about $1 million for the year. Savings from energy projects are used to fund additional projects. The focus is on short-term projects with quick payback.

No action taken.

6. Report from the Chair

Chairperson Stormont reported on relevant issues raised during Mayor and Council meetings since the last Commission meeting, which included the City Budget for 2027, transit safety, and the approval of a groundwater pumping permit for Project Blue from ADWR. He also shared that the American Battery Factory has secured sufficient contracts to begin production of batteries at the Aerospace Research Campus.

No action taken.

7. Discussion of Public Power Options (Mayor & Council tasking: March 3, 2026)

Commissioner Rivera discussed the report he has been working on for public power options. He said he'd like to incorporate recommendations from the DCP report into his recommendations. (See attachment 1.)

Commissioner Weaver reviewed the proposed tasking from Council Member Schubert and has started addressing elements of the tasking. The Commission discussed the Tucson CCA Roadmap and Tucson Municipalization Roadmap shared by Commissioner Weaver. (See attachments 2 and 3.)

EM Catanzaro shared some of the slides he presented to the Mayor and Council on the Tucson Renewable Energy Enterprise (TREE). EM Catanzaro also offered to share the research he has collected on public power options with the Commission at the July or August meeting.

No action taken.

8. Discussion of Energy Collaboration Agreement (Mayor & Council tasking: April 7, 2026)

The Commission discussed the Energy Collaboration Agreement Projects, Rev 1 document that Commissioner Weaver shared. There was also discussion about a recent DoE policy change that will significantly impact the Efficiency Arizona program and the definition of a Neighborhood Resilience Alliance.

Commissioner Bachmann provided a brief summary of the Community Engagement & Communication Subcommittee meeting held on May 28, 2026, where CRO Luna presented a draft of her ECA implementation framework. During the subcommittee meeting, members and guests asked questions and provided feedback that CRO Luna will incorporate into a revised framework.

No action taken.

9. Approval of Distributed Capacity Procurement (DCP) report and cover letter

The Commission reviewed the final report and cover letter submitted for forwarding to Mayor and Council. Motion by Chair Stormont, duly seconded by Commissioner Shepp, to approve the report and cover letter for distribution to Mayor and Council. The motion was passed by a roll call vote of 6 to 0.

10. Data Center Report progress update

Chair Stormont thanked Commissioners Brown and Weaver for submitting updates for their sections of the report. He will be compiling the inputs for review by the Commission.

Commissioner Shepp suggested incorporating some of the recommendations from the Climate Mayors Data Center Report into the Commission's report.

The Data Center Energy Subcommittee is planning to meet to review the Climate Mayors report to see what can be added to their section. Commissioners Gomez and Rivera will be joining the subcommittee. Commissioner Rivera will be chairing the subcommittee.

No action taken.

11. Subcommittee reports

There was some discussion about submitting missing LARs and meeting minutes for subcommittees.

Chair Stormont mentioned the need to reach out to the Complete Streets Coordinating Council to see how the currently inactive GSI subcommittee could work with them on the issues identified by neighborhood associations with implementing approved Safe Streets Mini-Grant projects.

Commissioner Shepp suggested that the Los Reales subcommittee meet with the Environmental Services Advisory Committee and the Tucson Parks and Recreation Commission concerning methane emissions and potential health risks at the Los Reales Sustainability Campus. She will reach out to the other commission chairs.

Community Engagement & Communication Subcommittee report provided during agenda item 8.

No action taken.

12. Future agenda items and determine meeting dates/times after the summer

Commissioner Shepp suggested inviting Carlos De La Torre, Director of Environmental Services, and Frank Bonillas, Superintendent of the Los Reales Sustainability Campus, to brief the Commission about the current status of the campus. Chair Stormont will invite them to present at a future meeting.

Discussed options for new meeting days and/or times after the summer. Also discussed the possibility of going to virtual meetings as an alternative to the current hybrid meetings. No decision was made at the meeting, since there should be some new Commissioners appointed in the near future.

No action taken.

13. Adjournment – 6:00pm

Chair Stormont adjourned the meeting at 6pm.

Attachment 1
Public Power Commissioner's Recommendation

Commissioner Rocky Rivera Opinion on Public Power

Executive Summary

After the March 17 Study Session regarding the Energy Collaboration Agreement (ECA) and the TEP Franchise extension, I suggest a pivot toward **distributed municipal ownership.** To meet Tucson's 2030 Carbon Neutrality goals, the City must move beyond voter level utility takeover and instead focus on the immediate establishment of **Municipal Utility Districts (MUDs)** for new development and resilience hubs.

Strategic Policy Principles

1. Decoupling Growth from Resource Depletion

The proposed Desert Data Centers present a significant challenge to Tucson's Water/Energy Nexus.

- **Recommendation:** The Commissioner supports the Unified Development Code (UDC) amendments requiring **closed-loop cooling** and **100% renewable matching** for high-load industrial users.
- **Objective:** Ensure that industrial expansion does not cannibalize the grid capacity required for residential electrification or deplete the local aquifer.

2. Operationalizing Option 3: Municipal Energy Hubs

The most fiscally sound pathway to public power is the **incremental municipalization** of new growth.

- **The Hub Model:** By establishing City owned solar + battery storage systems in Ward 5, the City creates islands of resilience. These hubs can provide emergency cooling and charging during extreme heat events while generating revenue for the General Fund.
- **Direct Pay (IRA Section 48E):** The City has a narrow window (closing July 2026) to leverage Direct Pay provisions, allowing us to receive cash reimbursements for 30 to 50% of the capital cost of these hubs.

3. Leverage in Franchise Negotiations

A 25-year Franchise Agreement extension without specific **Public Power Carve Outs** limits the City's future agility.

- **Policy Ask:** The Franchise Agreement should explicitly permit the City to operate its own distribution infrastructure for Sustainability Pilots and Municipal Hubs without incurring prohibitive wheeling charges from TEP.

4. Advancing the "Tucson Resilient Together" Mandate

Ward 5 contains high concentrations of Heat Vulnerable census tracts.

- **Focus:** Municipal hubs should be treated as **critical public infrastructure**, similar to sewers or roads. This is not merely an energy policy; it is a public safety policy designed to prevent heat-related mortality during grid instability.

Recommended Actions for Council

1. **Sponsor a Municipal Hub Pilot:** Direct the City Manager to identify a specific City owned parcel in Ward 5 for a first of its kind Municipal Resilience Hub.
2. **Codify Data Center Guardrails:** Support the Commission's recommendations for the Mayor and Council to adopt strict Water/Energy Performance Standards for all Special Use industrial permits.
3. **Establish a Sustainable Infrastructure Fund:** Use a portion of the Franchise Fee revenue to specifically fund the Direct Pay matching requirements for municipal solar projects.

Key Data

- **Fiscal Benefit:** Municipal solar hubs utilize Direct Pay, essentially providing a federal subsidy for City owned assets that TEP (as a private entity) cannot access in the same manner.
- **Resource Impact:** A single water cooled data center can use upwards of 100 million gallons of water annually, enough to support thousands of residential households.

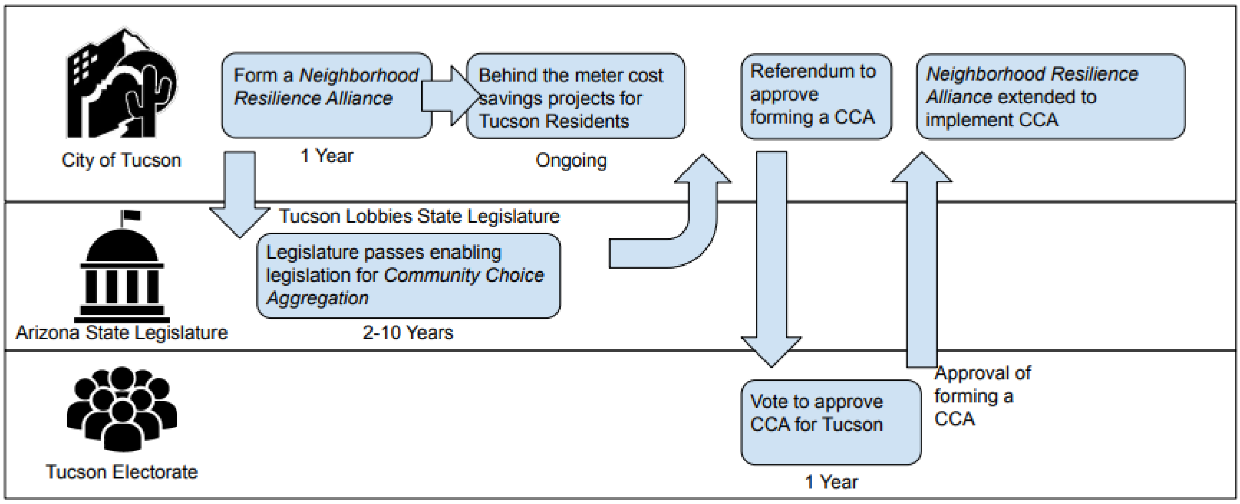
Strategic Advice from the Commissioner

I think it best we emphasize **Option 3 (Municipal Hubs)** as the most probable path for all stakeholders. It avoids the $4 billion debt of buying TEP entirely but offers more control and better rates than the status quo.

The biggest barrier to having the city power new housing or commercial developments is Arizona's Certificate of Convenience and Necessity (CC&N).

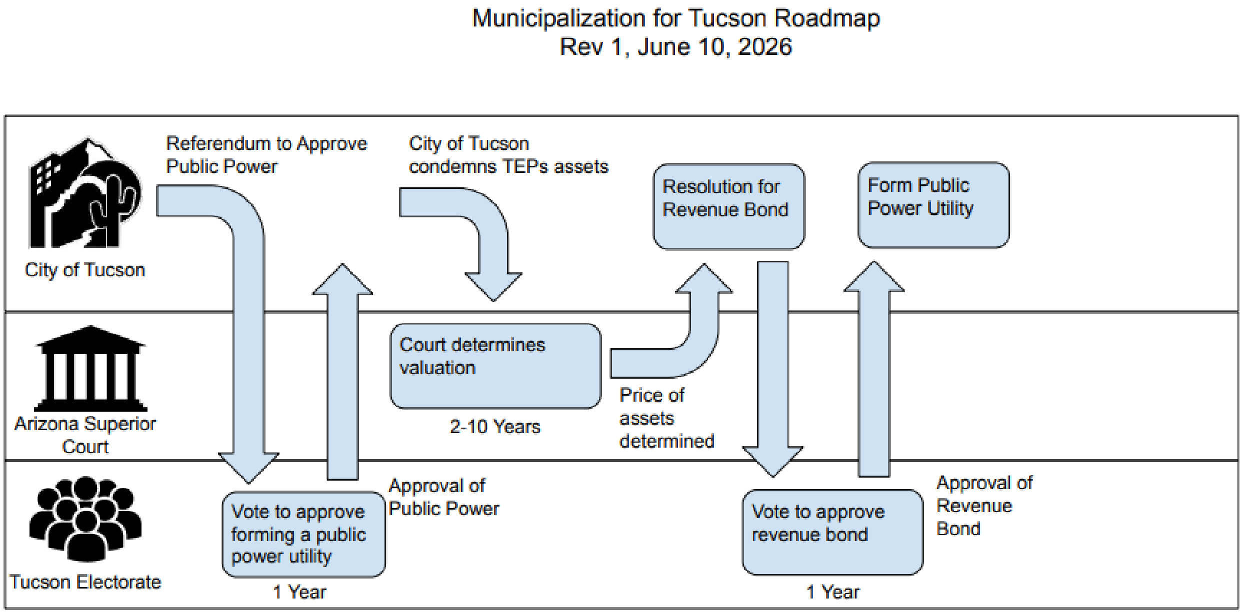
- The Monopoly Rule: TEP has the exclusive legal right to sell electricity to any resident within its designated territory. If the City tried to sell solar power to a new apartment complex, TEP could sue for breach of their state granted monopoly
- The Behind the Meter Loophole: A developer can build their own solar, but the City owning it and selling it to the developer is legally grey.

Attachment 2
Tucson CCA Roadmap



Sources:
https://www.nationalccea.org/what-is-cca
https://www.epa.gov/green-power-markets/community-choice-aggregation

Attachment 3
Tucson Municipalization Roadmap



Sources:
https://www.publicpower.org/system/files/documents/municipalization-forming_a_public_power_utility.pdf
https://www.azleg.gov/ars/9/00514.htm
https://www.eminentdomainreport.com/what-is-a-proper-public-use-under-arizona-eminent-domain-condemnation-law
https://www.azleg.gov/ars/48/02465.htm

Attachment 4
Energy Collaboration Agreement Projects

This Cup Will Hold Buckets

Investments in durable cost savings for Tucson residents

Submitted to the Commission on Climate, Energy, and Sustainability Community Engagement and Communications Subcommittee.

Author: Garrett Weaver
Contributors (who provided ideas and feedback): Terry Finefrock, Lee Stanfield, Shelly Gordon, Rick Rappaport, Tres English, Duane Ediger, Bruce Plenk, and Julie Dittmer.
Date: May 27, 2026

Introduction

Higher energy prices and the affordability crisis is hurting Tucson residents. Electric utilities and those payments are becoming more of a burden to working families in our community. Low income residents spend 11% of their income on electricity. https://docket.images.azcc.gov/E000051019.pdf?i=1778689697734 Increases in utility prices disrupt household budgets for these residents.
Increasing home energy efficiency for low income residents and multi-family homes will reduce utility bills for low and middle income residents in a durable way, prepare households for increasing summer temperatures, while also increasing property values, reducing peak load on the grid, and reducing greenhouse gas emissions.

History

The Arizona Corporation Commission (ACC) approved an Electric Energy Efficiency Resource Standard (EERS) in 2010. The standard requires the state's regulated utilities, including Arizona Public Service Company (APS) and Tucson Electric Power (TEP), to save 22% of electricity sales in 2020 as a result of energy efficiency programs. https://www.swenergy.org/wp-content/uploads/Arizona-utility-EE-fact-sheet-Dec-2020.pdf

These programs included rebates for efficient heating and cooling systems; programs for multifamily housing; low-income household weatherization; and programs for "advanced rooftop controls" for commercial heating, ventilation and air conditioning systems.

In 2025 the ACC voted to repeal these rules, with commissioners saying "It served its purpose, everyone has met the requirements, now it's time for them to go away."
https://azcc.gov/news/home/2025/09/17/acc-votes-to-initiate-repeal-of-electrical-energy-efficiency-mandate

There is still benefit for providing these programs, "SWEEP Arizona representative Caryn Potter noted that TEP in its own energy-efficiency program report estimates that every dollar spent on energy-efficiency programs delivers $5 in net benefits."
https://tucson.com/news/local/business/article_b9110286-fef1-11ec-b593-639a10dc6314.html

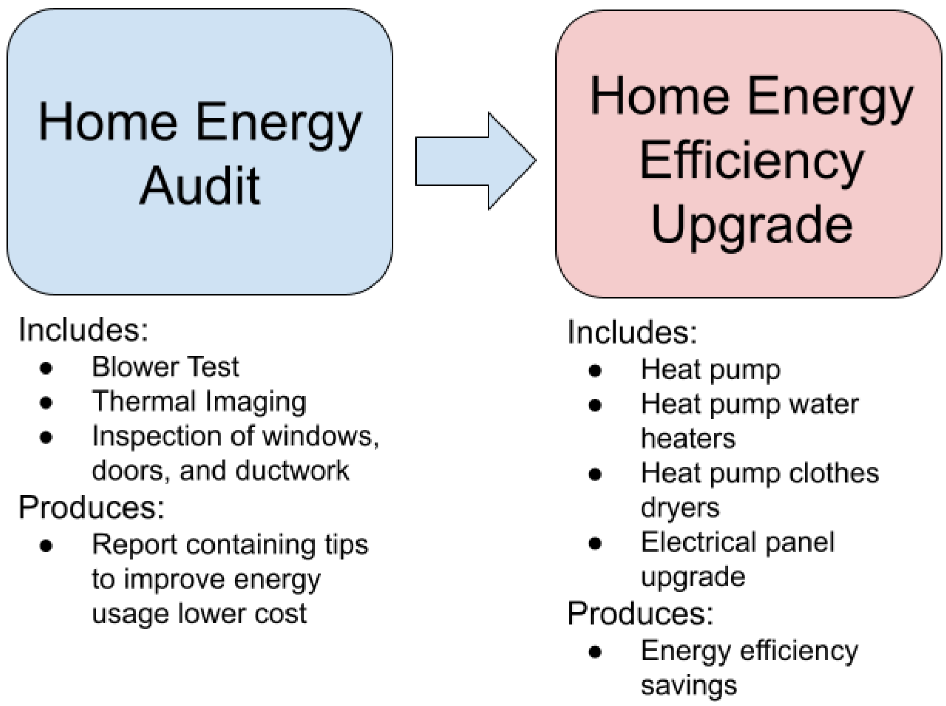
As of 2026, TEP continues to offer energy efficiency rebates. Offering rebates for high efficiency heat pump quality installation up to $720, which can pay for up to 5% of project costs, depending on installation.
https://www.tep.com/efficient-home-program/

In 2024 Arizona launched Efficiency Arizona, funded through a $153 million U.S. Department of Energy (DOE) Home Energy Rebates program. This program provides rebates for appliances for high efficiency heat pumps, heat pump water heaters, electric stoves, and heat pump clothes dryers. The program is funded through 2029.
https://efficiencyarizona.com/efficiency-arizona-issues-1000th-rebate-adds-new-participating-retailer-to-program/

Under the Inflation Reduction Act, home owners could receive a tax credit, capped at the greater of either 30% of project costs, or $150, for a home energy audit. On December 31, 2025 this tax credit ended.
https://www.energystar.gov/about/federal-tax-credits/home-energy-audit

Proposed Projects

1. City of Tucson should offer free energy efficiency audits to residents by paying energy audit contractors to do this work. This would implement ECA item 5.f. The outcome of this would be to recommend which energy efficiency or weatherization projects would benefit an individual household the most. This will start the process for residents to access existing programs offered by TEP and the State of Arizona to reduce their electric bills through the upgrade to more efficient appliances, insulation, or other home upgrades



2. Tucson should contribute to workforce training for energy efficiency upgrades by leasing properties from homeowners to upgrade for facility retrofit workforce training. This would support Section 8.b in the ECA. According to Pima Counties Climate Action Now Plan (PimaCAN), "Pima County's ambitious planned investments in GHG reduction will generate significant growth in several high-quality career fields. **Facility retrofits**, solar microgrids and new EV charging infrastructure all rely on skilled technicians and construction tradespeople." (https://www.epa.gov/system/files/documents/2024-03/pima-county-pcap.pdf, 77) Investing in this workforce, through training, will grow the workforce to support the upgrades needed today for 200,000 post-WWII / pre-1980 homes in the Tucson metro region. There are efforts underway, such as the Green Retrofit II program at Pima Community College.

Source: allweatherroof.com. License: CC BY-NC 4.0

3. Behind The Meter (BTM), Distributed Generation (DG), and Virtual Power Plants (VPP) for low and middle income residents. This would support ECA item 5.b. To reduce community, ratepayer and utility costs, to improve electricity reliability and resident standards of living, City of Tucson and Tucson Electric Power (TEP), as well as Pima County, State of Arizona and Arizona Solar providers, collaborate to launch a Program to subsidize ratepayer owned solar-storage systems within the distribution grid by residential, commercial (Shopping Malls/Apartments/HOA, etc.) and Public Service facilities (Governments; Schools; Hospitals; Law Enforcement, etc.). Subsidize 100% of system costs for low-income, poverty level ratepayers, and ~50% for other ratepayers.

Source: https://guardianhome.us/battery-backup-power-pace-florida/ License: CC BY-NC 4.0

4. Fund existing Solar Empowerment Program efforts. This would support ECA item 5.c. According to sources at the Sonoran Environmental Research Institute, their Solar Empowerment Program has a waiting list of projects more than a year long. Additional funding could accelerate these projects.

Examples of Programs in Other Regions

Home Energy Audits

The Arapahoe Weatherization Assistance Program (Arapahoe County Colorado), offers free home energy audits for low income residents. The program is available for residents making less than 60% of the State Median Income (SMI).
https://www.arapahoeco.gov/your_county/county_departments/community_resources/assistance_programs/weatherization_assistance/index.php#collapse5990b0

Oklahoma Municipal Power Authority offers free energy audits to residential customers served by the utility. This includes all customers, regardless of income.
https://www.ompa.com/about/residential-energy-audit/

Energy Efficiency Retrofit Training

"Sacramento Municipal Utility District leased a home from its owner for a year (September 2009- 2010) and operated it as a lab house where NREL scientists tested different equipment and energy usage scenarios. SMUD opened the house to builders, contractors, and the general public for tours and training."
https://www1.eere.energy.gov/buildings/publications/pdfs/building_america/ba_casestudy_smud_fairoaks_hot-dry.pdf

Behind The Meter (BTM), Distributed Generation (DG), and Virtual Power Plants (VPP)

Cape and Vineyard Electrification Offering is designed to be a turnkey program that makes it financially feasible and logistically approachable for households of all income levels to adopt solar panels, heat pumps, and batteries, and to realize the amplified benefits of using the resources together. In total, the program is providing free or heavily subsidized solar panels and heat pumps to 55 participating households, 12 of which also received batteries at no cost.

The batteries installed through the program are enrolled in ConnectedSolutions, a state program that pays battery owners who send power to the grid when needed. Because the pilot footed the bill for the batteries, these payments will go to the Cape Light Compact, rather than residents, to help defray the cost of the program.

"Instead of having several siloed programs, it's all being presented to the customer in a package, which makes everything work together better."

https://www.canarymedia.com/articles/electrification/massachusetts-solar-heat-pump-battery-pilot

Building on These Projects

Many of the above projects could be done under the umbrella of a *Neighborhood Resilience Alliance*, this is similar to a Sustainable Energy Utility, except it will do all work *behind the meter*. An institution, within the city government, could facilitate and coordinate projects for the city, residents, and commercial properties related to behind the meter distributed generation deployment, virtual power plants, and home energy efficiency retrofit programs.

This is similar to the CCA 3.0 concept by Local Power LLC.
https://localpower.com/CCA_30Entire.html
Which facilitates voluntary customer investment in small, modular distributed energy resources on homes and businesses that reduce demand for grid and pipeline resources, rather than centralized renewable generation that adds to such demand. CCA 3.0 looks to energy efficiency to finance energy equity, views more home appliances, such as water heaters, as distributed energy resources, and finances upgrades either under municipal bonds, or through working through a credit union. In fact, Tucson could implement much of this vision, sans the community wide energy procurement, as a *Neighborhood Resilience Alliance*, with current state policies.

Additional financing for community energy projects could be provided from large industrial users of energy. According to a recent Rewiring America report on data centers, if data centers pay for 50% of the costs of household energy efficiency projects it is on-par, on a cost per kilowatt hour basis, with building new generation. Investing in home energy efficiency projects would not only reduce residential energy bills in households that undertake these projects, but it would free up much needed energy generation for a growing set of industrial users, who demand the energy. A city institution, focused on community energy projects, such as a *Neighborhood Resilience Alliance* could take money from new large industrial users, and use that funding to take on projects to reduce residents energy bills and reduce greenhouse gas emissions.
https://www.rewiringamerica.org/newsroom/press-releases/peak-demand-report-2025

Possible projects for a *Neighborhood Resilience Alliance* includes:

- TREE Pilot - Neighborhood-scale solar and storage.
- Municipal Neighborhood Resilience Hub - A City-controlled or public-serving hub that provides cooling, charging, communications, and emergency support without selling electricity or distributing power across property lines.
- Municipal Building Resilience Hubs / City Facility Upgrades - Building from existing examples like Donna Liggins and identifying what continued support or expansion could look like.
- Weatherization, Home Repair, and Energy Affordability Upgrades - Household-facing work that could connect to the broader implementation structure.

Footnote

Title of this paper is a reference to Arizona Corporation Commission Chair Thompson's remark that "the energy efficiency mandate… has done very little to delay the need to construct new generation. You can't use a cup to fill a generation gap that demands buckets." https://azcc.gov/news/home/2025/09/17/acc-votes-to-initiate-repeal-of-electrical-energy-efficiency-mandate

Attachment 5
Cover Letter to Mayor & Council for Distributed Capacity Procurement Report

Commission on Climate, Energy and Sustainability
P.O. Box 27210
Tucson, Arizona 85726-7210
(520) 791-4213 (Voice)
(520) 791-2639 (TDD)
(520) 791-4017 (FAX)

Dear Mayor Romero, City Council Members, and Manager Thomure,

The Commission on Climate, Energy, and Sustainability submits this letter alongside its report, "Distributed Capacity Procurement: A Model for Fast and Cheap Clean Energy in Tucson."

Distributed Capacity Procurement (DCP) is a utility-led model in which TEP deploys, owns, and operates rooftop solar and battery storage at homes and businesses across Tucson. Such a model allows for **rapid deployment of clean energy that can place downward pressure on energy prices**.

The Commission continues to explore other pathways to clean energy and presents this information as another option for the Mayor and Council's consideration. Pursuing DCP additionally dovetails well with the Energy Collaboration Agreement.

Notably**, the City and TEP have already demonstrated this model** works. The battery installation at the Donna R. Liggins Recreation Center -- utility-owned, rate-based, and co-located with solar at a City facility -- is a DCP project in everything but name. A full DCP deployment would scale up what the City and TEP have already built together.

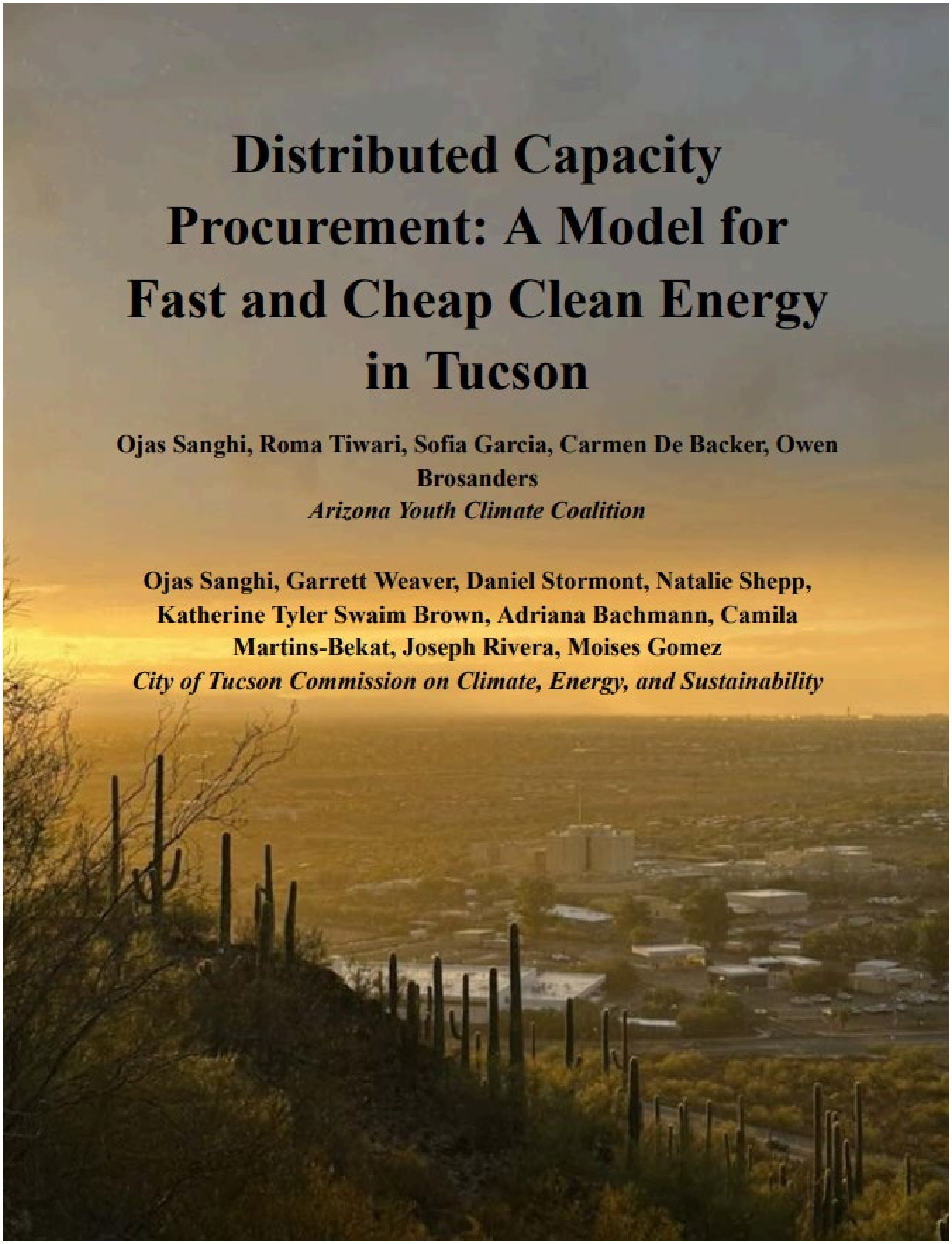
The full report, including fiscal modeling, case studies, and implementation roadmap, is enclosed for the Mayor and Council's review. The Commission is available to present its findings and welcomes the opportunity to discuss next steps.

Respectfully submitted,
Commission on Climate, Energy, and Sustainability
City of Tucson

On behalf of the Commission members:

Daniel Stormont (Chair), Ojas Sanghi, Garrett Weaver, Adriana Bachmann, Camila Martins-Bekat, Katherine Tyler Swaim Brown, Natalie Shepp, Joseph Rivera, Moises Gomez

Attachment 6
Distributed Capacity Procurement Report



Distributed Capacity Procurement: A Model for Fast and Cheap Clean Energy in Tucson

Ojas Sanghi, Roma Tiwari, Sofia Garcia, Carmen De Backer, Owen Brosanders
Arizona Youth Climate Coalition

Ojas Sanghi, Garrett Weaver, Daniel Stormont, Natalie Shepp, Katherine Tyler Swaim Brown, Adriana Bachmann, Camila Martins-Bekat, Joseph Rivera, Moises Gomez
City of Tucson Commission on Climate, Energy, and Sustainability

Table of Contents

0. Executive Summary

Tucson needs a way to deploy clean energy quickly, affordably, and at scale. Because Tucson Electric Power controls the local distribution system, the most viable near-term path is not to bypass TEP, but to redirect its monopoly utility business model toward distributed clean energy. Distributed Capacity Procurement (DCP) offers that path.

Tucson's clean capacity problem is on an accelerated timeline. Arizona electricity demand grew 8% in 2025, and in the coming years, TEP expects a 5-6% annual growth in energy demand. New centralized generation requires a lead time of multiple years and cannot fill that gap in. Distributed energy resources (DERs), by contrast, deploy in months, and when aggregated into a virtual power plant they deliver firm capacity at substantially lower net cost than either gas peakers or utility-scale batteries.

Any Tucson clean energy strategy that operates on a climate-relevant timeline must work through TEP. DCP is designed precisely for that: it makes DERs utility-planned, utility-owned, and rate-based, converting the same profit incentive that has historically produced under-deployment of distributed resources into a vehicle for accelerated deployment, with no new state legislation required.

Here, we explain the DCP model, why it is suitable for Tucson's situation, and provide discussion on case studies from across the country and pathways to a DCP deployment in Tucson.

0.1 Roadmap of the Report

Section 1 explains why Tucson needs clean capacity quickly: the convergence of demand growth, coal retirements, climate deadlines, and the structural slowness of centralized supply.

Section 2 explains why Tucson cannot route around TEP, and why CCA, public power, and deregulation are not near-term alternatives.

Section 3 explains how DCP works, what differentiates it from consumer-led DER adoption and centralized generation. It also features **case studies of other DCP programs** across the country.

Section 4 explains why Tucson is especially well-suited for a DCP deployment: unmatched solar resources, favorable inertia from the Energy Collaboration Agreement, TEP's existing operational precedent (Donna Liggins microgrid), and the current political moment.

Section 5 proposes a Tucson-specific DCP design, covering program goals, siting analysis, fiscal architecture, customer participation, equity safeguards, workforce strategy, and the regulatory pathway to ACC approval.

0.2 Findings from Fiscal Modeling

A 5%-of-peak DCP solar deployment (138 MW across roughly 23,000 homes) carries an upfront capital cost of $345.5 million and a levelized cost of energy of $141 per MWh. That figure is already below the low end of the gas peaker range of $149 to $251 per MWh.

When the benefits of avoided transmission and distribution (T&D) costs are incorporated using conservative assumptions, the effective LCOE of a DCP solar deployment drops to $132 per MWh. The cost of a DCP deployment of this size translates to ~$6 per ratepayer per month.

Adding distributed storage yields a combined LCOE of $230 per MWh, still cheaper than the upper end of the gas peaker range and providing the dispatchable, firm capacity that solar alone cannot.

0.3 Recommendations for the City of Tucson

The City has five near-term opportunities to advance DCP using its existing legal authorities and relationship with TEP:

1. **Initiate an ECA-based collaboration with TEP at City-owned buildings**, modeled on the Donna Liggins Recreation Center microgrid. The Donna Liggins battery, financed through TEP's rate base, is already a DCP-style project; scaling that template across City facilities, parking structures, and City-managed affordable housing is a direct application of ECA Sections 5(b), 6(b), and 7.
2. **Request that TEP conduct a feeder-level locational benefit analysis** identifying substations and distribution corridors where targeted solar + storage deployment would yield the highest avoided transmission and distribution costs. This analysis is a prerequisite for an actionable DCP pilot design.
3. **Engage TEP's next Integrated Resource Plan as a formal stakeholder**, submitting comments that request DCP inclusion as a modeled resource alternative to equivalent peaking capacity.
4. **Explore whether Project Blue's economic development agreement can include a DCP financing commitment.** A pre-purchase of capacity from a utility-owned distributed solar + storage portfolio would offset the data center load with clean local resources without imposing the cost on existing ratepayers.

5. **Conduct listening sessions and town halls** for citizens and property owners to provide feedback on the DCP structure; and what possible incentives TEP could provide under a DCP program.

1. Tucson's Clean Capacity Problem

1.1 Increasing Energy Demand

The U.S. electrical grid is experiencing demand growth at a pace unseen in decades [1]. Compound annual growth rates for summer and winter peak demand are the highest since the North American Electric Reliability Corporation (NERC)'s tracking began in 1995, according to the agency's 2025 Long-Term Reliability Assessment [2].

The same report found that 13 of 23 North American assessment areas now face elevated or high resource adequacy risks over the next five years.

In the next decade, the primary demand driver is predicted to be AI-linked data centers. The International Energy Agency (IEA) projects U.S. data center energy consumption will more than double from 183 TWh in 2024 to 426 TWh by 2030 [3]. This will account for nearly half of all U.S. electricity demand growth this decade [4,5].

This national trend has been playing out in Tucson as well. Project Blue, a $3.6 billion Amazon-linked data center campus being constructed in Pima County, would demand 286--350 MW initially, potentially rising to 600 MW. This would make it TEP's largest customer and consume roughly 15 - 20% of current generation capacity [6,7].

Arizona's electricity demand grew 8% in 2025, four times the national average, largely from data centers. State data center electricity consumption could reach 16.5% of total Arizona electricity by 2030 [8]. In the coming years, TEP expects an 5-6% annual demand growth [9]. In this context, it is critically important that TEP find methods to operationalize new generation capacity fast.

1.2 Increasing Energy Rates

Although the economics of energy are more complex than typical supply-demand interaction, the various concurrent pressures on the energy system have placed upward pressure on electricity prices -- the U.S. Bureau of Labor Statistics reported the Consumer Price Index (CPI) electricity index rose 6.7% in 2025 [10].

Indeed, PJM's December 2025 capacity auction for the 2027/2028 delivery year cleared at record-high prices while still falling short of the reliability target by roughly 6.6 GW [11].

Simultaneously, there is great concern among Americans and voters around the cost of energy bills. Arizona faces already inflated energy prices: an analysis of utility bills across the Southwest found that the average monthly electricity bill in Arizona between 2019 and 2024 was about $160, more than 43% higher than neighboring New Mexico despite Arizonans using 33% more energy per capita [12] [13].

In addition, rate increases in Tucson seem set to increase further: TEP has filed for a 14% rate increase (June 2025), seeking to recover $1.7 billion in grid investments since 2021.

In the national and local context of sensitivity to cost of living and energy prices, it is important that TEP find ways to deliver grid capacity and reliability without raising energy prices.

1.3 The Urgency of the Climate Crisis

The scientific consensus on what must happen and by when is unambiguous. To limit global warming to 1.5 degrees C, global net CO_2 emissions must fall by roughly 45% from 2010 levels by 2030 and reach net zero around 2050 [14]. Every year of delay narrows the remaining window for action.

The consequences of inaction are already materializing in the electricity sector. During a heat wave, electricity demand rises as people run air conditioning while at the same time the grid's own generation and transmission capacity degrades [15]. The U.S. experienced approximately twice as many weather-related power outages in the decade from 2014-2023 as it did in the decade from 2000-2009, with the nation's electrical grid increasingly strained by infrastructure that was never designed for the present-day climate [16].

In 2024, Tucson's weather broke records for the hottest July and October, enduring 109 consecutive days of triple-digit heat [17]. That relentless heat translates directly into grid stress: TEP's local energy grid peaked at 2,502 MW in August 2025, driven by back-to-back days with temperatures of 111 and 112 degrees [18].

It is against this backdrop that TEP's 2023 Integrated Resource Plan (IRP) takes on particular significance, as it targets net-zero emissions by 2050 [19]. To get there, the same IRP plans for 2,240 MW of new renewable generation and 1,300 MW of new energy storage through 2038, including the recently constructed 200 MW/800 MWh Roadrunner Reserve battery.

To meet these ambitious clean energy goals and align with the deadlines of 2030 and 2050, Tucson’s grid of the future must begin taking shape today.

1.4 Centralized Energy Supply is Slow and Expensive

We need an unprecedented increase in energy supply to match dramatic demand growth, but traditional generation resources cannot be built fast enough.

For natural gas plants, Mitsubishi Power's director stated utilities need to place orders as long as seven years out, and Siemens Energy's North America president admitted the market cannot produce enough gas turbines to meet current demand [20,21]. Nuclear power is even slower: the Vogtle expansion -- the only U.S. nuclear plant completed in decades -- took 15 years from construction start to commercial operation and cost $36.8 billion, 2.5 times its original estimate [22]. Globally, nuclear construction times averaged 9.4 years from 2013 to 2022 [23].

Furthermore, even when generation capacity is built, interconnection to the grid becomes a major bottleneck. Lawrence Berkeley National Lab (LBNL)'s 2025 "Queued Up" report found over 2000 GW of projects actively seeking grid interconnection [24]. Notwithstanding "ghost projects," that is roughly twice of total installed U.S. capacity [25]. Median time from interconnection request to commercial operation is now over 4 years, and only 13% of projects submitted since 2000 have reached operation [26].

New transmission lines compound the problem further: siting and permitting a major interstate line can take a decade or more on its own. For instance, the SunZia line took almost 20 years from proposal to operation [27]. This means that even projects that clear the interconnection queue face additional years before electrons reliably reach customers.

The result is a compounding supply-side crunch. TEP must meet surging demand from population growth, electrification, and data center load, all within a procurement and construction environment where new centralized resources take years to permit, finance, interconnect, and build.

Centralized generation is structurally ill-suited to fill that gap in time. The speed, scalability, and deployability that the moment demands point toward a different answer.

1.5 Distributed Energy Resources Are The Solution

The resources best suited to the current moment are not large and centralized. Instead, it is the small distributed energy resources (DERs) already sitting on rooftops and in parking lots across Tucson

DERs' core advantage for the current crisis is speed. Residential solar installation takes 2-6 months from contract to operation; commercial systems take 4-6 months [28]. Battery storage can be added to existing systems in days. These timescales are orders of magnitude faster than the 5-15 years required for centralized generation [29–31].

DERs also bypass the infrastructure bottlenecks constraining centralized build-out: they use existing rooftops, parking lots, and building electrical systems; require no new transmission lines (avoiding the decade-long permitting and construction process for high-voltage corridors); and reduce the energy losses incurred from long-distance transmission [32]. And because they scale incrementally, capacity additions can be matched to actual demand growth rather than requiring large, lumpy capital commitments years in advance.

DERs are also cheaper, especially when they are aggregated and controlled as a virtual power plant (VPP), which enables the utility to treat DERs as a firm, dispatchable resource. The Brattle Group found that a VPP composed of residential thermostats, water heaters, EV chargers, and batteries can provide peaking capacity at 40% lower net cost than a utility-scale battery and 60% lower than a natural gas peaker plant [33]. The deployment timeline is just as compelling: in just four months, National Grid stood up a VPP reaching 250 MW of peak-shaving capacity in Massachusetts and New York [34].

Furthermore, unlike gas turbines, battery manufacturing capacity is actively expanding. Following passage of the One Big Beautiful Budget Act (OBBBA), which preserved the federal Investment Tax Credit (ITC) for standalone storage intact, domestic battery manufacturing and contracting has accelerated considerably to meet growing utility demand.

1.6 Conclusion

DERs are poised to serve as the solution to the grid's tripartite problem of clean, cheap, and fast energy. However, there is a structural constraint. Tucson does not control its own energy supply; TEP does. Section 2 examines why Tucson must work with TEP to address the clean capacity problem.

Furthermore, the speed and cost advantages of DERs are only realized if the utility actively procures, integrates, and compensates them. DERs have not yet deployed at the scale the moment demands, and the reasons why are rooted in utility incentive structures, program design, and regulatory frameworks. In Section 3, we examine those barriers and how Distributed Capacity Procurement could serve as a model to deploy DERs at scale.

2. Why Tucson Must Work Through TEP

2.1 TEP's Regulated Monopoly

In Arizona, electric utilities operate as regulated monopolies, receiving exclusive franchises to serve defined geographic areas. No public service corporation may begin construction of a utility line, plant, or system without first obtaining a Certificate of Convenience and Necessity (CCN) from the Arizona Corporation Commission [35]. Once issued, the CCN grants the holder exclusive rights to serve customers within the defined territory, and no other company may provide the same service in that area unless it obtains its own certificate [35,36].

TEP is the investor-owned utility (IOU) that holds an exclusive CCN for the Tucson metropolitan area. As a result, no individual, organization, or city government can produce electricity (like from rooftop solar) at one property and deliver-that electricity to a neighboring property by running a power line between them.

This has several real-world consequences:

- A commercial building with surplus solar cannot sell its excess electricity directly to the building next door. It can export back to the TEP grid, but it cannot transact directly with a neighboring customer.
- A landlord or developer cannot build a single solar installation to power multiple separate parcels of land they own, even if those parcels are adjacent.
- The City of Tucson cannot build, own, and operate a community microgrid serving multiple customers in TEP's service territory

The only entity legally positioned to run wires across property lines in Tucson (and, more broadly, own and operate energy infrastructure serving multiple customers) is TEP.

This is why TEP must be a partner in any large-scale distributed clean energy deployment in Tucson. In other words, for the City of Tucson to accelerate clean energy deployment, instead of seeking to route around TEP, they must work with TEP to design programs, structures, and incentives that make TEP a willing partner in the energy transition.

2.2 Alternative Energy Sourcing Models

There exist alternative energy sourcing models that seek to replace or extend aspects of the investor-owned utility model. However, they each have significant challenges that limit their immediate policy deployment. Here, we articulate reasons why some alternative models are not suitable for the goal of rapidly sourcing and delivering clean energy.

2.2.1 Community Choice Aggregation/Energy

Community Choice Aggregation (CCA), also called Community Choice Energy (CCE), is a model in which a local government (city, county, or group of municipalities) assumes responsibility for procuring the electricity supply for its residents and businesses, while the incumbent utility (like TEP) retains ownership and operation of the physical distribution wires and poles. Under a CCA model, the community entity can choose to buy electricity from renewable sources on behalf of its customers, effectively giving local governments control over the energy mix without requiring them to own the grid.

CCAs have proven powerful in states where they are legal. Ten states have enacted CCA enabling laws: California, Illinois, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Ohio, Rhode Island, and Virginia [37]. Collectively, CCAs now serve roughly 15% of Americans.

However, Arizona does not have CCA-enabling legislation. Tucson has placed CCA legislation on its state legislative agenda, but passage requires sustained legislative support that does not currently exist [38].

Moreover, CCAs address energy supply procurement, not the physical deployment of generation, transmission, and distribution infrastructure. As a result, it does not address concerns around aging grid infrastructure, including but not limited to:

1. the cost of capital expenditures on infrastructure upgrades
2. old power lines downing during extreme weather events
3. the comparative lack of grid resiliency from centrally-located energy supply, compared to distributed networks of energy generation
4. addressing peak demand strain despite the average low utilization of existing grid infrastructure.

2.2.2 Public Power

Public power -- also called a municipal utility -- is a model in which a city or local government owns and operates the electric distribution system directly, rather than a private investor-owned utility. Public power utilities exist across the United States: examples include the Los Angeles Department of Water and Power (LADWP), Sacramento Municipal Utility District (SMUD), and Austin Energy. These entities are governed by elected boards or city councils and are accountable directly to residents rather than to shareholders or out-of-state investors.

The idea of converting Tucson to public power has attracted significant interest, and the City of Tucson formally explored it. An April 2025 draft feasibility study commissioned by the city estimated that a public takeover of TEP's distribution assets could cost between $1.4 billion and

$3.7 billion [39], but still deliver energy bill savings within a decade. Meanwhile, TEP commissioned its own study through the Brattle Group, which put the cost at over $4 billion and projected that the additional cost of service from a city-run utility would escalate to an extra $900 per year per residential customer after 20 years [40–42].

Regardless of the cost debate, there are numerous practical barriers to public power in Tucson:

1. TEP will resist a forced sale of its assets through legal, regulatory, and political channels. Condemnation of a regulated utility's assets requires litigation, valuation disputes, and years of legal proceedings.

2. The timeline is incompatible with climate urgency. A successful transition to public power would take multiple years from the start of legal proceedings, even if TEP were to cooperate with the process. The climate crisis will not wait.

3. The financing burden is enormous. A $1.4 - $4 billion acquisition would require the city to issue substantial debt. Tucson is already suffering from decreasing tax revenue and a multi-million-dollar budget deficit [43]; taking on billions in utility acquisition debt would constrain the city's fiscal capacity for decades.

4. There is no guarantee of faster clean energy deployment. Owning the grid does not automatically mean deploying clean energy faster. Municipal utilities face their own bureaucratic inertia, political constraints, and capital access challenges.

Public power remains a legitimate long-term vision, but given the pressing timelines of the climate crisis (50% clean energy by 2030 and 100% by 2050) as well as specific obstacles Tucson faces, public power is not a viable near-term strategy.

2.2.3 Deregulated Market

Electricity deregulation refers to the policy of introducing retail competition into electricity markets, allowing consumers to choose their electricity supplier rather than being captive to a single regulated monopoly. Deregulation, in its fullest form, unbundles electricity generation from transmission and distribution, creating competitive wholesale and retail electricity markets. Examples include CAISO, ERCOT, and ISO-NE.

Arizona is not deregulated, and achieving deregulation would require an act of the state legislature. Arizona briefly attempted retail deregulation in 1998, but the effort stalled in court and the law was ultimately repealed [44].

To pursue a deregulated market in Arizona today would require passage of new state legislation authorizing it; federal (FERC) approval of market structure changes; years of market design, infrastructure upgrades, and implementation; and willingness from incumbent utilities (TEP and APS). None of these conditions are remotely close to being met in 2026.

Furthermore, deregulated markets do not automatically produce rapid clean energy deployment. They produce cost competition, which can (or cannot) favor renewables depending on fuel prices, market design, and other factors.

2.4 Conclusion

Arizona's electricity system is defined by a regulated monopoly structure that makes it impossible for individuals, communities, or the city government to deploy clean energy infrastructure at scale without TEP's participation. Alternative models -- community choice energy, public power, and full deregulation -- each require either years-long legislative battles, enormous capital and legal costs, or both. Meanwhile, Tucson faces an accelerating climate emergency, with record-breaking heat already claiming lives and straining the grid.

Tucson therefore needs a model that can do three things at once: deploy clean capacity rapidly, operate within TEP's legal monopoly, and give TEP a financial reason to participate. Distributed Capacity Procurement is designed for precisely that problem.

3. Distributed Capacity Procurement: A Utility-Aligned Model for Fast DER Deployment

3.1 Why the Status Quo Monopoly Model Under-Deploys DERs

The current model of DER deployment is bottom-up: individual homeowners go out and install DERs (solar panels, batteries, smart thermostats) on their own homes, financing it themselves and expecting to get paid back from reduced energy bills within ~10 years. The fundamental barrier to scaling this up is business model alignment.

Under the "rate base" model, TEP earns money in a specific and predictable way: it spends capital on infrastructure (centralized generation, transmission and distribution infrastructure, etc), and the ACC allows it to earn a regulated rate of return on that capital [45]. Currently, DERs are treated primarily as customer-side assets that the utility accommodates (through export rates and interconnection processes) rather than as utility-owned assets that TEP actively deploys and earns a return on.

Thus, every rooftop solar panel a customer installs reduces utility revenue without reducing the utility's fixed-cost obligations. A 2018 Black & Veatch survey found 71% of utilities considered the "utility death spiral" -- where customer solar adoption triggers rate increases that drive further adoption -- to be a real and possible outcome [46].

This structural misalignment has led many utilities to resist distributed solar through reduced export compensation, interconnection delays, and fixed charges. For instance, in 2016, the ACC replaced net metering with the Resource Comparison Proxy (RCP), significantly lowering the value received from exporting rooftop solar energy back to the grid.

Furthermore, even if there was no such business model conflict, the current model is not ideal for several reasons:

1. it is not reasonable to expect enough individual homeowners to personally finance enough rooftop solar to meet our clean energy goals
    a. the scale is fragmented -- hundreds of thousands of separate customer decisions rather than one coordinated deployment plan
    b. furthermore, the motivation is generally to reduce one's own electricity bill after a multi-year payback period; a relatively weak driver of deployment

2. deployment is limited to customers who can afford to own suitable rooftops, a substantial structural barrier. In 2023, only 22% of solar-adopting households were in disadvantaged

communities (DAC), despite 31% of U.S. households being in a DAC [47].

3. this form of solar adoption is not centrally planned by the utility, and there is no systematic incentive to deploy solar in the locations that would most benefit the distribution grid

In summary, the current model of DER deployment has been slow, bottom-up, and has structural limitations that prevent it from delivering clean energy or grid reliability at scale or speed. Without reform, this model will continue to under-deploy clean energy because no mechanism exists to align TEP's investment incentives with large-scale clean energy deployment.

3.2 Introduction to Distributed Capacity Procurement

Distributed Capacity Procurement solves the business-model problem identified in 3.1 by making DERs utility-owned, rate-based assets aligned with grid planning. The SEPA/Sparkfund whitepaper defines DCP as "a model for utilities to procure and utilize DERs at scale" in which "utilities plan, deploy, own, and manage customer-sited DERs based on where they can provide the most grid value" [48,49].

The critical distinction from traditional consumer-directed deployment is who drives siting, ownership, and dispatch decisions. Under the conventional model, individual homeowners and businesses decide independently whether and where to install solar, creating a fragmented, uncoordinated pattern that utilities cannot control or optimize.

Operationally, DCP works as follows:

1. TEP conducts a grid needs assessment to identify constrained nodes -- locations where peak demand strains local infrastructure or where new load is anticipated.
2. It then issues procurement targets for those locations: a specified capacity of solar, storage, demand response, or combined DER systems to be deployed within a defined geography.
    a. Assets may be sited behind the meter (on customer rooftops/facilities) or in front of the meter (on utility-owned or leased land).
    b. TEP retains dispatch rights, enabling it to call on the aggregated DERs as a virtual power plant when grid conditions require.
3. Because TEP determines siting and interconnection as part of the deployment plan, projects bypass the multi-year interconnection queue that constrains conventional generation.
4. TEP owns the assets, adds them to its rate base, and earns its regulated return.
5. Customers receive cheaper, cleaner energy and improved reliability.

6. The monopoly model becomes a vehicle for the energy transition rather than an obstacle to it.

This model produces five distinct advantages over both traditional centralized generation and uncoordinated consumer-driven DER deployment, which we elaborate on in the sections that follow:

1. Speed: DCP bypasses interconnection queues entirely. Sparkfund, a company that works with utilities to operationalize DCP programs, estimates it can deploy 200+ MW per year through DCP, compared to the 6.7 MW enrolled by the Rocky Mountain VPP Watt Power Program (a consumer-directed program with no centralized siting authority) [50].

2. Grid-targeted peak reduction: Because TEP selects deployment locations based on grid needs assessments, DERs are placed precisely where they alleviate congestion, shave local peaks, and defer costly transmission and distribution upgrades. Under the status quo model, benefits accumulate in arbitrary neighborhoods where individual homeowners happen to act.

3. Cost: DCP assets enter the rate base, which means there is no upfront payment. TEP's rate structure follows a progressive structure based on the amount of kWh consumed, and there are further opportunities to finetune the rate increases to ensure low-income communities are protected. Combined with the avoided cost of transmission upgrades and peaker plants that DERs displace, the net cost to ratepayers can be substantially lower than conventional capacity additions.

4. Clean energy at scale: Utility-led procurement means deployment is not constrained by individual homeowner economics, access to credit, or roof suitability.

5. Full-stack grid services: Because DCP assets are utility-dispatched and grid-connected under TEP's operational control, they can provide the complete range of grid services -- including energy capacity, frequency response, voltage support, and backup power -- that individually owned and operated DERs typically cannot deliver.

3.3 How DCP Can Improve Grid Capacity and Utilization

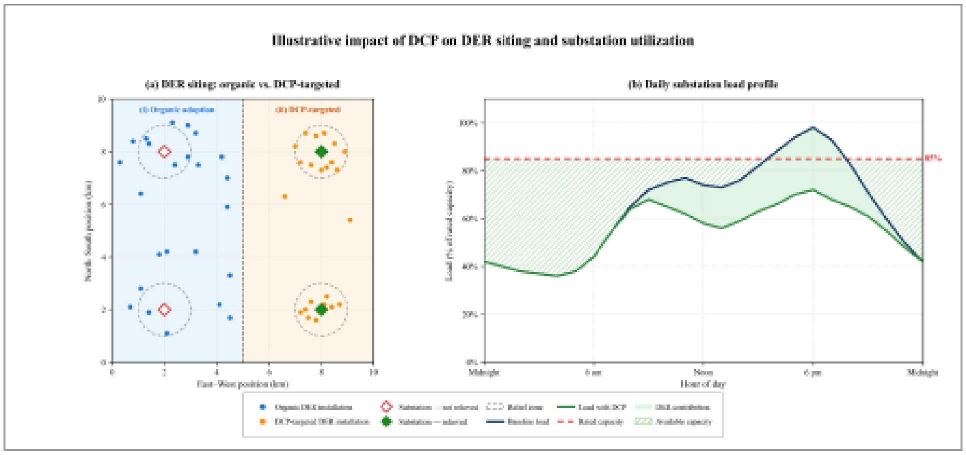


Figure 1: Illustrative impact of DCP on DER siting and substation utilization. Illustrative, fabricated data.

The U.S. electric grid averages only 50–55% utilization across the year [51]. The grid is designed for the single worst hour of the year, and as a result, ratepayers finance infrastructure that is underutilized most of the year. The economic stakes of this underutilization are large. A March 2026 analysis by The Brattle Group, commissioned by the Utilize Coalition (an industry group comprising Google, Tesla, Carrier, Verrus, SPAN, and Renew Home) found that better utilization of the existing U.S. power system could save consumers more than $100 billion over the next decade [52]. A complementary analysis by Duke University's Tyler Norris reached similar conclusions on grid flexibility as a core affordability lever [53].

This creates a precise and tractable opportunity for DCP. TEP, as the distribution system operator, has granular visibility into exactly which substations, feeders, and radial lines are approaching their limits, and exactly when. With this information, instead of waiting for customers to install DERs wherever they choose, TEP can direct deployment to ease congestion at the constrained nodes. That is, DCP represents a distributed, utilization-focused approach to grid infrastructure, which is now widely being recognized as critical to ensuring energy affordability and clean energy adoption.

Panel (a) of Figure 1 shows the consequence of each approach. Under organic adoption, installations scatter across the service territory in a pattern independent of where the grid is stressed; as a result, constrained substations remain unserved. Under DCP, TEP strategically places assets to relieve every stressed substation.

The load profile in Panel (b) shows what targeted deployment achieves. Without DCP, an illustrative substation might exceed the capacity threshold in the evening hours. But with DCP-deployed solar + storage, those resources could be dispatched during the peak hours, shaving the highest-stress window. Peak load falls from 98% to approximately 72% of rated capacity, preventing a capital upgrade. Spare capacity is now unlocked that TEP can use for load growth, enabling increased average grid utilization and grid capacity while expanding clean energy usage putting downward pressure on energy prices.

3.4 DCP's Fiscal Alignment with TEP's Business Model

Distributed Capacity Procurement (DCP) harnesses the structural incentive present in Arizona's regulated monopoly model, creating a straightforward financial alignment.

Because DERs under DCP are utility-owned capital assets, they enter the regulated rate base just

like a natural gas plant or transmission line. Instead of relying on mandates, DCP works with the profit incentive already embedded in the monopoly structure.

The utility earns its authorized rate of return on the investment. Ratepayers benefit from avoided or deferred transmission and distribution upgrades, reduced reliance on fossil peaker plants, and capacity market revenue.

By designing a program in which TEP itself deploys clean energy assets (solar arrays, battery storage) in the distribution network and earns a regulated return, it turns the profit incentive of the monopoly into a vehicle for large-scale clean energy deployment.

3.5 Benefits for the Grid and for Ratepayers

3.5.1 Cheap Energy Resources

A Brattle Group analysis found that procuring peaking capacity through a residential VPP carries a net cost approximately 60% lower than a gas peaker plant and 40% lower than a utility-scale battery alone [33]. DOE's own projection placed the net cost of a new 400 MW VPP at $43 per kilowatt-year, against $99 per kilowatt-year for an equivalent gas peaker [54].

These advantages compound through infrastructure deferral. Consolidated Edison's Brooklyn/Queens Demand Management VPP program deferred approximately $1 billion in substation investment by deploying targeted efficiency measures and distributed solar, delivering substantial long-term savings to New York ratepayers [55]. The Brattle Group estimated that a 60 GW national VPP build-out could avoid $15 to $35 billion in infrastructure costs over a decade [33].

As TEP enters its own aging infrastructure investment cycle, the capital deferral case for DCP is directly applicable. These economics are further strengthened by federal policy. The Investment Tax Credit (ITC) for standalone battery storage was preserved in full in the One Big Beautiful Budget Act (OBBBA). As utility-owned rate-based assets, TEP's DCP batteries would be eligible for the ITC, directly reducing capital costs and improving both TEP's balance sheet and the ratepayer cost figures presented in our fiscal model. Our LCOS estimates do not capture this benefit and are therefore conservative with respect to federal incentives (see Appendix B.3.1).

3.5.2 Clean Energy and Environmental Justice

VPPs maximize Arizona's abundant solar resource by charging distributed batteries during peak renewable generation and discharging during evening demand peaks, "firming" intermittent generation and reducing the need to dispatch fossil fuel peakers.

The equity implications are significant: according to EPA data, U.S. peaker plants are located near communities with disproportionately high concentrations of low-income households, who bear the greatest burden of localized air pollution [56]. A DCP framework that prioritizes VPP enrollment in identified load pockets directly addresses this inequity.

PUC-regulated investor-owned utilities are best positioned to directly deliver clean energy equity benefits to communities because in states like Arizona, there is no other body with the capital, power, and technical skill required to deploy clean energy resources at scale and speed.

3.6 Case Studies

Several utilities have already attempted versions of utility-led DER deployment at scale. These programs vary in design and market interaction. Together, they establish two things:

1. DCP-style deployment is operationally feasible and can move faster than customer-driven adoption; and
2. program design determines whether ratepayers see real benefits.

The most directly applicable case is Xcel Energy's Capacity*Connect, the nation's first explicitly utility-led DCP program at scale. Additional case studies are analyzed in Appendix D.

3.6.1 Xcel Energy - Capacity*Connect

On October 3, 2025, Xcel Energy filed a proposal with the Minnesota Public Utilities Commission (MPUC) called Capacity*Connect, the nation's first utility-led DCP program at scale. The program proposes deploying up to 200 MW of distributed battery storage at strategic grid locations by 2028, with Sparkfund as the deployment services partner [57].

The budget ranges from $152 million (minimum 50 MW) to $430 million (full 200 MW), translating to approximately $2,150 per kW [57] [58].

The program's structure is entirely utility-owned and utility-operated. Xcel's planning team identifies grid-constrained locations. Sparkfund handles site evaluation, host marketing, equipment procurement, data facilitation, and operations and maintenance for the life of the program.

Individual battery units range from 1-3 MW each (1 MW is roughly shipping-container sized), sited at local businesses, commercial/industrial facilities, or nonprofits, including within environmental justice communities [58]. Host organizations receive direct payments.

Xcel plans to generate over 65% of Capacity*Connect revenue by providing MISO with bulk system capacity (resource adequacy), benefiting all Xcel Minnesota customers [59].

In early April 2026, the Minnesota Public Utilities Commission approved Xcel Energy's Capacity*Connect Phase 2, authorizing the deployment of up to 200 MW of utility-owned battery storage. PUC Commissioner Hwikwon Ham called the program "a vital step toward modernizing the energy grid and meeting the growing electricity needs of our communities," noting that battery storage and virtual power plant models would help create a "more equitable energy future that delivers real value back to the communities" [60,61].

The program has also attracted direct private co-investment: Google committed $50 million to Capacity*Connect to secure clean power supply for a planned Minnesota data center -- an early signal that large industrial load customers are willing to fund the distributed grid capacity that serves their needs.

The PUC required an interim assessment at 50 MW, regular status reports, and a comprehensive evaluation by an independent party [60]. By affirmatively approving the DCP model as a legitimate mechanism for utility capital planning, the MPUC has established DCP as a replicable regulatory framework rather than just a speculative proposal [62].

Some concerns about Capacity*Connect are addressed in Appendix D.1. As discussed there, most of these critiques are specific to Minnesota's MISO market context and do not apply in

Arizona, where TEP operates as a vertically integrated monopoly without a competitive retail market.

3.6.2 Emerging National Momentum

Capacity*Connect's approval has triggered rapid replication across regulatory jurisdictions. In November 2025, Baltimore Gas & Electric filed a 15 MW utility-owned battery program with the Maryland Public Service Commission explicitly modeled on Capacity*Connect; the MD PSC advanced it in Order No. 92281 (Case No. 9715) [63]. A full case study is in Appendix D.5.

The New Jersey Board of Public Utilities and Dominion Energy Virginia have each since released RFIs seeking input on expanded DER/BESS deployment under analogous frameworks. And a Virginia electric cooperative has already launched a DCP-style distributed battery program [64].

The DCP model is no longer a single-utility pilot; it is an emerging utility planning paradigm spreading across multiple RTOs and regulatory regimes within a single filing cycle.

3.7 Conclusion

DCP offers a structurally elegant solution to the utility business model's historical misalignment with distributed energy. By making DERs utility-owned infrastructure rather than customer-driven threats to revenue, it enables utilities to profit from deploying the resources that can be built fastest.

The grid strain is unambiguous: demand is growing at record rates, centralized generation takes half a decade or more to build, and interconnection queues have effectively frozen the pipeline.

DERs, when deployed via DCP, can be operationalized in just months. They can provide clean energy, improve grid resilience, increase grid utilization, and put downward pressure on rates.

For Tucson, the convergence of massive data center demand (Project Blue), coal retirement timelines, existing demand response infrastructure, and Arizona's unmatched solar resource creates a scenario where DCP's core proposition -- fast, utility-aligned distributed capacity -- directly addresses TEP's most pressing challenges.

4. Why DCP Fits Tucson

The preceding sections have established what DCP is and why it is the right structural model for clean energy deployment within a regulated utility. This section makes the Tucson-specific case.

Tucson presents a particularly strong case for DCP deployment, driven by the convergence of several local factors that collectively make distributed solutions both more feasible and more urgent here than in most comparable U.S. markets.

4.1 High Solar Potential + Regional Exports

Arizona has the nation's high solar capacity factor [65] and the 3rd largest battery energy storage capacity in the U.S. [66], creating favorable conditions for distributed solar-plus-storage at scale.

According to Google's Project Sunroof, approximately 95% of buildings in Tucson are solar-viable, with capacity for 3,100 additional MW [67]. **This would be more than Tucson's entire peak load.**

That value extends beyond Tucson's borders. TEP already participates in the Western Energy Imbalance Market (WEIM), enabling it to sell DCP-provided resources across the region when demand is high, reducing TEP's exposure to expensive peak power purchases and passing those savings to ratepayers. The value of these well-deployed distributed clean energy resources will only increase as TEP integrates deeper with Western electricity markets through the coming Southwest Power Pool (SPP) Markets+ platform.

4.2 City of Tucson x TEP Energy Collaboration Agreement

The Energy Collaboration Agreement (ECA) between TEP and the City of Tucson opens up significant opportunities to dovetail with a large-scale DCP deployment program.

A formal partnership with the City of Tucson through the ECA can substantially enhance both the efficiency and the equity of DCP deployment. The City and TEP each hold assets and capabilities that the other lacks.

The City could contribute building energy usage data; zoning and land use plans; future development projections; access to public and affordable housing sites for early deployment; and connections to community organizations that TEP alone would struggle to reach. At the same time, TEP can contribute detailed grid condition data; feeder-level load forecasts; DER performance modeling; and technical program administration expertise. Taken all together, a two-way collaboration between the City and TEP enables more precise, cost-effective targeting of distributed resources.

This potential can be seen in specific sections of the ECA:

Section 5(b) of the Agreement commits both parties to expanding the use of DERs, explicitly naming rooftop solar, battery energy storage systems, and microgrid community resiliency hubs. A DCP program is the direct programmatic mechanism for fulfilling this commitment at scale.

Section 6(b) establishes a joint commitment to developing Resilience Hubs with solar and BESS technology at key City locations. DCP's locational targeting methodology -- siting assets at grid-constrained points that also serve community facilities -- operationalizes this provision. The Donna Liggins microgrid, already financed through TEP's rate base, is an existing example of Section 6(b) in practice (more on that below).

Section 7 commits both parties to prioritizing low-income residents and extending program benefits into vulnerable communities. DCP's ability to direct asset siting toward underserved distribution feeders provides the geographic and demographic precision that makes this commitment actionable rather than aspirational.

Finally, under Section 10, TEP is obligated to pay the City $56.2 million over the 25-year term, with funds contractually restricted to the clean energy, resilience, equity, and workforce goals established in Sections 5 through 9. These funds can support community outreach, equity-targeted siting analysis, and workforce development for DCP without cost to ratepayers.

Additionally, a City partnership also unlocks financing opportunities not directly available to TEP, such as government grants that only municipal governments qualify for. It also opens up options for blended financing structures, such as where City grant funding covers upfront installation costs on public/ affordable housing sites while TEP compensates participants over time for grid services. Such an approach can significantly reduce the cost burden on ratepayers while expanding the program's geographic and demographic reach.

4.3 TEP Operational Precedent

4.3.1 Donna Liggins Microgrid

An example of locally integrated clean energy that falls under DCP lies in microgrids, which can both increase clean energy utilization and improve grid resilience by providing backup power during a grid outage.

The City of Tucson and TEP are currently collaborating on a microgrid at the Donna R. Liggins Recreation Center, which is a crucial cooling and community center.

Donna Liggins at the time of the collaboration initiating already had solar panels, but we learned at the 2026 Heat Summit that TEP and the City are installing a multiple-MWh battery at Donna Liggins, and -- crucially -- it was being paid for by putting it into the ratebase. In other words, this battery could be seen as **TEP's first DCP project.**

By engaging in this DCP-style deployment of clean energy resources, Donna Liggins is shaping up to be a case study of how DCP can be employed to improve energy resiliency and equity by aiding areas such as community centers or hospitals without engaging in expensive grid upgrades.

4.3.2 Existing Demand Response Programs

TEP already operates demand response and storage programs: the Smart Rewards smart thermostat program (18,000+ participants and 22,000 thermostats), the Energy Storage Rewards battery dispatch program ($120/kW per season), and commercial interruptible service programs [68] [69].

These existing programs provide operational infrastructure and customer engagement experience that could serve as building blocks for a DCP deployment.

4.3.3 Past Rooftop Solar Program

TEP launched a utility-owned rooftop solar pilot in 2015, procuring 3.5MW of solar capacity by installing solar panels on 600 homes. As part of the program, customers would pay a $250 one-time fee for installation then have a fixed monthly rate for 25 years. It was greatly successful and TEP sought to double the size of the program, but the Arizona Corporation Commission deferred expansion [70].

More details about the program are discussed further in Appendix E.1.5; but the popularity of the pilot among ratepayers proves appetite in Tucson for such a utility-led solar program, as well as proof of TEP's ability to operationalize and benefit from such a program.

4.4 Political Context - Rate Hikes and Demand Increases

Tucson's community has sustained and organized pressure for clean energy, and that pressure is currently directed squarely at TEP.

TEP filed for a 14% rate increase in June 2025 while the Arizona Attorney General has argued the increase should be capped at 4% [71] [72]. In January 2026, Attorney General Kris Mayes filed suit against TEP over ACC actions enabling those increases, calling it "blatant corporate greed," and held a public town hall in Tucson where dozens of residents testified about the impact on their lives [73].

Furthermore, a sustained local movement has pushed the City to explore municipal takeover of TEP's infrastructure, going far enough that the City commissioned a formal study.

Community anxiety around Project Blue has compounded this: many residents view the data center's electricity demand as a cost that will be passed to ordinary ratepayers, regardless of whether that concern fully reflects how utility rate-setting works in practice.

DCP directly addresses the conditions driving this frustration. It is a mechanism for TEP to deploy clean energy at scale, hold down infrastructure costs, and demonstrate alignment with community priorities. Indeed, Project Blue could offer a positive opportunity to finance the initial set of DCP with external developer money, enabling a cheap expansion of clean energy that actively places downward pressure on energy rates.

5. Implementing a DCP Program in Tucson

The preceding sections have made the case for DCP in principle. This section addresses its design in practice -- how a Tucson-specific DCP program should be structured to deliver on its promise.

5.1 Program Goal

A successful program achieves three things that TEP's current procurement approach cannot:

1. It deploys distributed capacity where the grid is stressed rather than where individual homeowners happen to act
2. It captures the full range of grid services that aggregated, utility-dispatched DERs can provide
3. It builds a regulatory track record of distributed capacity performance that positions DCP as a creditworthy component of TEP's resource mix in future IRP filings.

5.2 Siting and Grid Targeting

The technical foundation of DCP is locational targeting. The core claim of the model is not simply that distributed solar + storage are cheaper than centralized alternatives -- it is that the right resources deployed at the right locations deliver additional value by deferring specific, identified infrastructure investments.

TEP should conduct a full distribution system analysis to identify constrained substations, feeders, and radial lines approaching their rated capacity limits, and to project where new load growth will create new constraints within the planning horizon.

This analysis should produce a prioritized list of locations where distributed capacity would deliver the highest marginal value, expressed in terms of specific, quantified avoided infrastructure costs: substation upgrades, transformer replacements, peaker dispatch avoidance.

TEP should also prioritize facilities that carry direct resilience value -- cooling centers, fire stations, community health clinics, affordable housing complexes, and critical care facilities. A battery-backed solar installation at a cooling center in South Tucson provides capacity relief to the feeder during normal grid operations and maintains essential services during an outage or extreme heat emergency.

A systematic siting methodology should identify locations that are simultaneously high-value for grid relief, technically suitable for distributed generation, and situated in neighborhoods where the equity case for DCP investment is strongest.

5.3 Fiscal Analysis

The fiscal projections below are scoping-level estimates developed to illustrate potential program economics for stakeholder consideration. They are not intended to replace utility analysis. TEP would be expected to conduct its own detailed financial and grid modeling as part of any formal IRP or program proposal process.

We found that deploying enough solar for 5% of peak demand (138.2 MW/362,664 MWh deployed across just 23,000 homes) would require a total capex of $345.5 million and carries an annualized cost of roughly $33 million per year. Crudely spread across TEP's 451,936 ratepayers, that translates to approximately $73 per ratepayer per year, or about $6 per month.

The solar would be obtained at a levelized cost of energy (LCOE) of $141/MWh. Critically, this is already cheaper than the low end of a gas peaker plant ($149/MWh per Lazard's 2025 LCOE+ analysis), and well below the peaker range ceiling of $251/MWh. During summer, solar generation has meaningful coincidence with on-peak periods (3-7 pm), partially displacing peaker dispatch. When combining the solar with a battery, true dispatchability can be achieved at a cost of ~$230/MWh.

When avoided transmission and distribution costs are incorporated, the fiscal case strengthens further. Using extremely conservative assumptions of $15/kW-year in avoided transmission costs and $35/kW-year in avoided distribution costs, the avoided T&D value for a solar-only DCP deployment amounts to approximately $9/MWh, bringing the effective LCOE to $132/MWh. In a blended solar + storage DCP, the avoided T&D value could be north of $30/MWh, reducing the blended LCOE to <$200/MWh.

Beyond the LCOE analysis, TEP's integration into WEIM and the forthcoming SPP Markets+ platform in early 2027 provides additional value streams not captured in this model (see Appendix C.5 for more information). A DCP-enabled VPP changes TEP's net load shape and provides controllable flexibility, enabling reduction of costly real-time imports during tight hours and additional low-cost exports during surplus hours. The VPP also enables TEP to spread fixed grid costs across more users and more hours -- placing downward pressure on rates for all customers. These benefits are real but require TEP's own grid modeling to quantify precisely.

A more detailed breakdown of our fiscal analysis, including our many tunable assumptions, can be found in Appendix B, and the full fiscal model can be found in the companion Excel document.

5.4 Program Architecture

5.4.1 Eligible Technologies and the VPP Framework

A Tucson DCP program could be structured around three categories of DERs: BTM solar PV, solar + storage, and demand response devices (thermostats, water heaters, EV chargers). Each of these exist on a spectrum from pure energy production to pure flexibility.

TEP would retain dispatch authority over all DCP assets. During normal grid conditions, solar charges co-located batteries and reduces host-site consumption. During peak events, TEP instructs the VPP to discharge batteries and shed flexible loads across the enrolled portfolio, delivering firm capacity at the feeder level. This is the structural distinction that separates DCP from a consumer-directed solar program: TEP can plan against this capacity because it controls when and how the assets operate.

A pilot should include both dispatchable resources (solar+storage) as well as pure demand response in order to measure performance of each and generate data that informs longer-run program design.

5.4.2 Commercial and Industrial Customers

Large commercial and industrial customers should be the primary focus of early DCP deployment. Relative to residential recruitment, C&I sites offer substantially more capacity per enrolled location, lower administrative cost per megawatt, and participants with the operational sophistication to engage in long-term capacity agreements.

Tucson's current expansion of data center and logistics facilities creates a particular near-term opportunity. Data centers, warehouses, hospitals, universities, and large retailers typically have several characteristics that make them valuable early participants: flexible loads that can be shed or shifted during peak events, existing building management and energy monitoring infrastructure, and a financial incentive to reduce demand charges.

A Tucson pilot could target specific feeders where data center load growth is projected and deploy C&I-sited batteries to relieve the constraint before it requires a capital upgrade.

5.4.3 Residential Design

Residential DCP differs from C&I primarily in scale, enrollment overhead, and the centrality of trust. Each residential site provides 5-15 kW of capacity, requiring a much larger number of participants to achieve meaningful megawatt totals.

The administrative cost of recruiting, contracting, and maintaining relationships with hundreds of individual households is substantially higher per megawatt than the equivalent C&I program. Nevertheless, TEP's 2015 rooftop solar pilot deployed 3.5 MW across 600 homes and was immediately oversubscribed, establishing that residential appetite for utility-led solar exists in Tucson. Any future program should endeavor to remove as many barriers to participation as possible.

5.5 Customer Participation

5.5.1 Trust, Transparency, and Enrollment

Prospective hosts will have specific, concrete concerns, and the program cannot succeed if those concerns are met with vague assurances. The following questions must be answered in plain language:

1. What is TEP authorized to do with the equipment, and under what conditions?
2. How often will TEP need physical access to the property, and on what notice?
3. What happens if the host needs to re-roof or renovate?
    a. What happens in the case of issues like roof leaks?
4. Does a long-term hosting agreement complicate a future property sale, and what are the transfer or termination terms?
5. Can the host still install additional solar on remaining roof space, or does hosting TEP equipment foreclose that option?
6. What are the financial consequences if the host wants to exit early?

The former CEO of TEP, David Hutchens, captured the core value proposition of a utility-backed program in his 2016 description of the rooftop solar pilot: customers wanted to sign up, he said, because "we've got the big utility behind it... we don't have to worry about signing this crazy complicated contract, we don't have to worry about whether they're going to be in business in five years, don't have to worry about maintenance, etc."

DCP's enrollment strategy should lean into the trust factor that TEP's brand can bring.

5.5.2 Incentive Structures

The financial architecture of DCP participation must be generous enough to drive enrollment while remaining grounded in the actual grid value that distributed resources provide. Incentives that are too modest will not attract participants; incentives that are too generous relative to avoided costs will undermine the program's regulatory defensibility.

TEP's 2015 pilot offers one workable template:

1. frozen energy bills
2. all O&M conducted by TEP
3. commitment to accommodate one roofing upgrade over the program term.

Some other ideas could include:

1. flat percentage discounts on energy bills
2. upfront hosting payments (which could be income-qualified to advance equity goals)
3. guaranteed bill savings denominated in dollars rather than rates
4. direct $ payment to hosts

The right structure will likely vary by customer segment -- commercial hosts may prefer capacity payment structures that mirror the demand charge reductions DCP provides; residential hosts may respond more strongly to guaranteed bill savings that are immediately visible on monthly statements.

Academic research on DER enrollment consistently finds that peer effects matter substantially: when residents observe their neighbors participating in distributed energy programs, their own likelihood of enrollment increases significantly [74].

TEP's enrollment strategy should leverage this by targeting contiguous geographies and publicizing early participation within specific neighborhoods rather than running general service-territory advertising.

5.5.3 Solar Autonomy and Program Framing

A recurring tension in Arizona/Tucson is between utility involvement and customer independence over behind-the-meter assets. Some households adopt rooftop solar specifically to reduce reliance on TEP. A DCP model that grants TEP dispatch authority over assets on homeowner property may face resistance from this segment even where the financial terms are attractive.

The most productive framing positions DCP hosting as an alternative path to energy cost reduction, not a competitor to customer-owned solar. For a household that cannot qualify for solar financing or does not want the capital commitment and multi-year payback period of a conventional installation, DCP hosting offers immediate, guaranteed bill benefits without those barriers.

For the subset of households with strong solar independence motivations, DCP is not designed to be the right product, and it does not need to be; only a fraction of available rooftop area is required to achieve the program's grid targets.

5.6 Equity

5.6.1 Cost Allocation and Distributional Impact

DCP introduces an important structural equity concern: program costs socialized through general rate adjustments are borne by all ratepayers, including those who cannot participate (renters without rooftop access, households in multi-family buildings, low-income households, etc). If DCP is funded broadly but benefits accrue narrowly, it could function as a regressive transfer from low-income households to their more affluent neighbors (ie, those who own their home and are able to agree to the DCP program without having to consult a property manager).

This concern is real and must be taken seriously. It is also important to contextualize it accurately. Traditional utility infrastructure investments -- substations, transmission lines, peaker plants -- are also funded through socialized rates, and they deliver capacity benefits that are not distributed proportionally to those who pay.

DCP does not introduce a new type of cost burden; it redirects how infrastructure dollars are spent, investing it into distributed clean resources instead of centralized fossil-fuel capacity. The critical question is therefore not whether the program imposes costs on all ratepayers (it does, as all utility investments do) but whether those who bear the cost receive a meaningful share of the benefits.

Achieving this requires deliberate design choices rather than relying on market participation to produce equitable outcomes:

1. **Geographic targeting**: Prioritizing DCP deployment in neighborhoods with high energy burdens and documented grid stress, such as South Tucson, ensures that the infrastructure investment benefit reaches communities that have historically been underserved. High summer heat exposure and limited access to cooling make grid reliability and affordability especially critical in these areas.
2. **Enhanced low-income incentives**: Offering additional rebates or guaranteed bill savings for income-qualified customers offsets the cost burden they bear as ratepayers.
3. **Transparent cost accounting**: Linking DCP program charges explicitly to specific avoided infrastructure projects, not to generic rate adjustments, strengthens the argument that all ratepayers benefit from deferring expensive grid investments, regardless of whether they participate directly.

5.6.2 Geographic Targeting and Enhanced Incentives

Achieving equity in benefit distribution requires deliberate design choices. DCP's locational targeting methodology can be used to direct investment toward neighborhoods with high energy burdens.

Communities that suffer high heat burdens could also be places with low clean energy adoption and high grid stress. A DCP program that systematically directs deployment to these areas serves both its grid mission and its equity mission simultaneously.

5.7 Workforce and the Local Economy

Scaling DCP will require a trained local workforce capable of installing, commissioning, and maintaining distributed solar + storage systems.

The existing Tucson solar installation ecosystem provides a foundation. Technicians for Sustainability (TFS) is a Tucson-based, employee-owned B Corporation and certified solar design-build cooperative that has operated in Southern Arizona since 2003 and installed more than 48 MW of solar for residential and commercial customers.

Firms like TFS represent the type of local contractor ecosystem that a DCP solicitation can be structured to support: directing program contracts to established local firms ensures that ratepayer-funded grid investments generate local employment and keep capital within the Tucson economy rather than flowing to out-of-region contractors.

TEP should partner with the City of Tucson, Pima Community College, and relevant trade organizations to develop apprenticeship and certification pathways.

Sparkfund, the deployment services company that developed and operationalizes the DCP framework, can play a significant role in managing the complexity of program execution. They have deployed more than 3,200 projects across 43 states and constructed over 300 MW of energized assets [75] and can handle operations like hiring and managing solar installer subcontractors. TEP does not need to engage Sparkfund to adopt a DCP model, but Sparkfund's operational infrastructure can simplify processes. Sparkfund would be paid via contract with TEP.

5.8 Regulatory Strategy

5.8.1 Convincing the ACC

The most consequential institutional barrier to DCP implementation will most likely be securing ACC approval. In November 2024, Republicans gained a 5-0 majority on the ACC [76]. Soon after, in August 2025, they voted to repeal Arizona's Renewable Energy Standard and Tariff (REST) rules [77,78]. The commission also began the process of repealing utility energy efficiency rules in September 2025 [79]. Any DCP proposal framed primarily as a clean energy program will face an unfavorable reception from this Commission.

DCP must be positioned before the ACC as a least-cost infrastructure investment, not a renewable energy program. The program's cost-effectiveness case must be specific, quantified, and independently verifiable, because a general claim that distributed resources are cheaper will not survive adversarial scrutiny. Every major design decision should be developed with this framing in mind.

In addition, Arizona's data center buildout creates a specific opening. Maryland's Utility Relief Act and Illinois's pending legislation both create tariff structures that grant data centers faster interconnection in exchange for co-investing in distributed grid assets. As the state with rapidly increasing energy demand, Arizona has strong grounds to pursue analogous ACC rulemaking -- one that ties Project Blue-scale load customers to the distributed capacity investment those loads require. This reframes DCP not as a ratepayer cost but as a condition of large load interconnection.

The ACC case is also reinforced by the Utilize Coalition's findings that grid utilization could save U.S. consumers more than $100 billion over the next decade [52]. Utility executives nationwide are now citing this report when justifying distributed, flexibility-first capacity programs. When the ACC hears DCP framed not as advocacy but as the approach being endorsed by utility CEOs and validated by Brattle, the political calculus becomes favorable.

5.8.2 Starting a Phased Approach Without a Rate Case

TEP does not need ACC approval to begin implementing DCP. The Donna Liggins microgrid, TEP's first DCP-style project, was executed without a rate case, demonstrating that the regulatory authority to undertake targeted grid investments in distributed resources already exists under current ACC authorizations.

This points toward a deliberate phasing strategy: begin with pilot-scale investments at specific facilities where the grid need is clear and the community benefit is obvious, build an operational and performance track record, and use that evidence to support a formal ACC filing for the full-scale program.

The phased approach also provides a natural response to the competition concerns that third-party solar developers will raise -- a small, geographically bounded pilot with transparent performance reporting is much harder to characterize as utility overreach than a territory-wide program seeking immediate authorization.

Evidence from comparable state proceedings supports this approach. In California, Pacific Gas & Electric and other investor-owned utilities successfully implemented non-wires alternatives (NWAs) under California Public Utilities Commission (CPUC) oversight. These projects have relied on valuation and avoided-cost analyses, performance standards, and competitive solicitation processes.

New York's Reforming the Energy Vision (REV) proceeding offers a further parallel. Con Edison and other utilities were ultimately authorized to take on new roles as distribution system platform providers, but the process took several regulatory cycles and required iterative negotiation with a wide range of stakeholders [80].

5.8.3 Rate Design

Full-scale DCP will require new tariff structures or significant modifications to existing ones. TEP will likely need ACC authorization for a cost recovery framework that links DCP expenditures to specific avoided infrastructure investments.

The most defensible design links DCP charges directly to feeder-specific, quantified avoided infrastructure costs, framing the program as targeted grid investment rather than a clean-energy surcharge.

Con Edison's implementation of DER compensation frameworks under New York's REV required multiple tariff filings and was refined across several rate cases before reaching stable form. TEP should anticipate a similarly iterative process.

5.8.4 Resource Adequacy and IRP Integration

A consequential regulatory question is how DCP resources are classified within TEP's resource adequacy framework; namely, how much of DCP-deployed DERs will count as firm capacity.

Lawrence Berkeley National Laboratory's analysis of DER capacity value provides a guide: programs that begin under conservative capacity credit assumptions and grow their credit through demonstrated performance have a substantially better regulatory track record than those that lead with aggressive projections.

The Brooklyn-Queens Demand Management program followed this trajectory: Con Edison's distributed portfolio was initially assigned modest capacity values that expanded as field performance was verified through measurement and verification (M&V) protocols. TEP should enter the ACC process with conservative initial claims.

DCP must ultimately be embedded within TEP's IRP. TEP should aim to file IRPs with DCP programs linked to specific, identifiable infrastructure deferrals and a clear trajectory of capacity credit growth as the performance record accumulates.

6. Conclusion and Recommendations for the City of Tucson

The City has four concrete opportunities to advance DCP through its existing legal authorities and relationship with TEP:

1. **Initiate a collaboration with TEP to install utility-owned clean energy resources at City-owned buildings and properties**

The ECA obligates TEP and the City to collaborate on clean energy deployment across City facilities. The City should direct relevant staff to formally invoke ECA provisions to initiate a DCP-style pilot by installing utility-owned solar + storage at City-owned buildings, parking structures, and City-managed affordable housing. Relevant ECA provisions include 5b, 6b, and 7.

This can be modeled after the Donna Liggins Center microgrid partnership, which showed that utility-owned distributed resources on City property can satisfy regulatory, fiscal, and community objectives simultaneously. A structured DCP expansion of that model, sized and sited through a locational benefit analysis, is a direct application of the ECA's existing terms.

2. **Request that TEP conduct a distribution system planning analysis to identify priority DCP siting locations**

The fiscal and operational cases for DCP depend heavily on avoided transmission and distribution costs, which vary significantly by feeder and substation. TEP has grid congestion data that outside parties do not.

The City should formally request that TEP conduct a feeder-level locational benefit analysis identifying the substations, feeders, and distribution corridors where targeted solar + storage deployment would yield the highest T&D deferral value. This analysis would produce the siting inputs required for an actionable DCP pilot design. The finalized analysis should be presented to the Mayor & Council or CCES.

3. **Direct City staff to engage TEP's next Integrated Resource Plan process as a formal stakeholder, with DCP inclusion as an explicit objective.**

DCP, as a utility-owned distributed resource class, must be modeled as a resource option in the IRP to receive regulatory consideration.

The City should submit formal comments in the next IRP cycle requesting that TEP include a DCP scenario covering utility-owned solar + storage aggregated as a VPP as a modeled alternative to equivalent peaking capacity.

4. **Explore whether Project Blue's economic development agreements can include a DCP financing commitment.**

Project Blue represents a multi-gigawatt data center load addition to TEP's service territory. The City has participated in negotiations over Project Blue's economic development terms. Those negotiations are an appropriate venue to explore whether the data center developer would agree to co-finance a DCP pilot. For example, Project Blue developers could pre-purchase capacity from a utility-owned distributed solar + storage portfolio as part of its clean energy procurement commitments.

5. **Conduct listening sessions and town halls** for citizens and property owners to provide feedback on the DCP structure; and what possible incentives TEP could provide under a DCP program.

By gathering public input, the City can lay the groundwork for a DCP pilot by understanding communities and neighborhoods that would be interested in a DCP deployment; identifying other benefits and drawbacks that may not be covered in this report; and begin shaping design parameters for a successful DCP deployment.

Tucson does not have time to wait for a different utility, a different legislature, or a different electricity market. DCP starts with the system Tucson has and changes what that system is used to build: a resilient, distributed clean energy future that uplifts every community.

7. Acknowledgements

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4. John Slocum, Vice President, Government Affairs, Sparkfund

Appendices

Appendix A. Clean Energy Fundamentals

A.1 Definition of Distributed Energy Resources

Distributed Energy Resources (DERs) are small-scale electricity generation, storage, and load-management technologies located at or near the point of energy consumption, rather than at centralized power plants. DERs include photovoltaic (PV) solar systems, battery energy storage systems (BESS), electric vehicles (EVs) and their chargers, smart thermostats, demand response programs, and combined heat and power units.

What distinguishes DERs from conventional generation is their scale and location. Traditional power plants generate electricity at a centralized facility and transmit it over long distances to end users, losing energy along the way. DERs, by contrast, generate or store energy close to where it is consumed, reducing transmission and distribution losses and relieving stress on the broader grid.

Individually, a single DER has a negligible effect on the grid. But when aggregated across thousands of sites and coordinated through software platforms such as Distributed Energy Resource Management Systems (DERMS), DERs can collectively behave like a large, dispatchable power plant — a configuration known as a Virtual Power Plant (VPP). This aggregation capability is what makes DERs relevant at utility scale, and is the foundational premise of Distributed Capacity Procurement.

A.2 Capacity Credit and Effective Load Carrying Capability (ELCC)

A power resource's **capacity credit** measures the fraction of its nameplate capacity that can be counted as firm, reliable generation. That is, capacity the grid operator can depend on during peak demand periods. It is expressed as a percentage of installed capacity. A conventional, dispatchable power plant can typically provide electricity at full power as long as it has sufficient fuel and is operational, so its capacity credit approaches 100%. Variable renewable energy plants, by contrast, may not be able to generate at rated capacity when needed, so their capacity credit is significantly lower.

A 10 kW residential battery, for example, does not contribute a full 10 kW of firm capacity: actual output depends on state of charge, household load at the time of the grid event, and operator dispatch constraints. Studies have shown that overlooking these decision-dependent and real-time failure uncertainties can overestimate a resource's true capacity contribution, undermining the reliability of resource adequacy planning. This has driven grid operators and regulators to adopt probabilistic methods; most prominently, **Effective Load Carrying Capability (ELCC)**.

ELCC defines capacity value as the extra load that can be added to the system once a resource is added, without degrading a chosen reliability index. ELCC's precision comes from the fact that it accounts for the timing, variability, and correlation of a resource's output with periods of system stress, not just its average or peak output.

ELCC is the standard by which DERs must be evaluated for **resource adequacy**, the requirement that a grid maintain sufficient generating capacity to meet peak demand under adverse conditions. The historic planning rule targets no more than one outage in ten years, implemented by building roughly 15% more resources than peak load projections, a precaution known as the Planning Reserve Margin (PRM). However, PRM planning has been criticized for often resulting in costly overbuilding of the system.

ELCC is now considered one of the most comprehensive methodologies available, as it determines the contribution of resources collectively rather than individually, making it particularly well-suited to portfolios of distributed, variable assets like those deployed under DCP. ELCC therefore provides the methodological foundation for how DCP-deployed assets would be credited in TEP's Integrated Resource Plan (IRP) and any future ACC resource adequacy proceeding.

A.3 Dispatchability

Dispatchability refers to a grid operator's ability to control when and how much power a resource delivers to the grid. It is foundational to resource adequacy: a grid cannot reliably meet peak demand unless it can direct generation to respond to real-time conditions, not just hope that supply and demand coincide.

Traditional generators achieve dispatchability through direct operator control: a gas peaker plant can be ramped up within minutes on command. DERs, by contrast, are distributed across thousands of customer sites and subject to physical constraints: a solar panel cannot generate at night, and a battery can only discharge what it has stored. For much of the early history of distributed energy, these characteristics were treated as fundamental barriers to utility-scale reliability.

That framing is now outdated. Certain DERs, especially battery storage systems, are inherently dispatchable, capable of charging during low-demand periods and discharging precisely when the grid needs them. When aggregated and coordinated through Distributed Energy Resource Management Systems (DERMS) and Virtual Power Plant (VPP) software, even less-controllable resources like rooftop solar can be managed as a coherent, dispatchable fleet. Operators can then use this fleet to perform the same reliability functions as conventional generators: **peak shaving** (reducing net load during high-demand hours), **load balancing** (distributing power across the grid to prevent localized overloads), and **contingency response** (maintaining stability in response to equipment failures or sudden network changes).

The practical implication is significant: dispatchability is no longer a categorical barrier to DER adoption at utility scale; it is increasingly one of the model's core selling points. A well-designed DCP program that incorporates DERMS and contractual dispatch rights can credibly claim the reliability performance of conventional capacity, while delivering it faster and at lower cost.

Appendix B. Full Fiscal Model

B.1 Modeling approach, scope, and known limitations

Here, we conduct an illustrative fiscal analysis of different types of DCP-style deployment of DERs. We calculate the LCOE and LCOS of such deployments, compare them to costs for other energy resources, and model potential avoided transmission and distribution (T&D) costs.

Notes:
- This is an illustrative fiscal analysis for reference. TEP should take this starting point and conduct a more in-depth fiscal analysis.
- Rooftop solar is known to have an order-of-magnitude higher LCOE than utility-scale solar. **There is potential to have such a project funded with a source other than ratepayer money, such a datacenter that cares deeply about becoming online quickly.**
- Source file available here.

Colors:
- Blue: solar-only
- Pink: includes storage (storage-only or storage + solar)

B.2 Solar-only analysis (LCOE)

B.2.1 Assumptions

Using the following assumptions,

Parameter	Value	Unit
Average kW per house (kW)	6	kW
kWh/year per kW installed (kWh/yr/kW)	1700	kWh/yr/kW
Installation cost per watt ($/W)	2.5	$/W
Tucson peak load (MW)	2764	MW
Solar system lifetime (years)	25	years
Annual O&M (% of CAPEX)	1	%
Annual capacity factor (%)	31	%
TEP ratepayers (#)	451936	#

and the following scenario assumptions:

Parameter	Value	Unit
Target solar capacity (% of Tucson peak)	5	%
Discount rate (%)	7	%

B.2.2 Baseline LCOE

We calculated the following values:

Metric	Value	Unit
Target solar capacity (kW)	138,200.00	kW
Houses needed (#)	23,033.33	#
Total installed CAPEX ($)	$345,500,000	$
Annual energy per house (kWh/yr)	10,200.00	kWh/yr
Annual energy (portfolio) (MWh/yr)	234,940.00	MWh/yr
Annual O&M per house ($/yr)	$150	$/yr
Total annual O&M cost ($)	$3,455,000	$/yr
Capex per home ($/home)	15000	$/home
Lifetime undiscounted cost ($)	$431,875,000	$
Lifetime total energy (MWh)	5,873,500.00	MWh
Lifetime undiscounted cost per MWh ($/MWh)	$74	$/MWh
Capital Recovery Factor (CRF)	0.08581051722	-
Capex per year ($/yr)	$29,647,534	$/yr
Total annual cost ($/yr)	$33,102,534	$/yr
Total lifetime cost ($)	$827,563,342	$
Levelized cost of energy ($/MWh)	**$141**	$/MWh

Using a very crude approach, and notwithstanding TEP's progressive billing rate, we calculated a rough monthly cost for ratepayers:

Annual cost per ratepayer ($/yr)	$73	$/yr
Monthly cost per ratepayer ($/month)	**$6**	$/mo

B.2.3 Scenario Analysis

We modeled multiple different scenarios of % peak load met with this utility-led rooftop solar deployment.

Scenario -->	Low Penetration	Baseline	Medium	High	Very High
Solar capacity (% of peak)	5	10	20	30	50
Target solar capacity (kW)	138,200	276,400	552,800	829,200	1,382,000
Houses needed (#)	23,033	46,067	92,133	138,200	230,333
Total installed capex ($)	**$345,500,000**	**$691,000,000**	**$1,382,000,000**	**$2,073,000,000**	**$3,455,000,000**
Annual energy per house (kWh/yr)	10,200	10,200	10,200	10,200	10,200
Annual energy (portfolio) (MWh/yr)	234,940	469,880	939,760	1,409,640	2,349,400
Annual O&M per house ($/yr)	$150	$150	$150	$150	$150
Total annual O&M cost ($)	$3,455,000	$6,910,000	$13,820,000	$20,730,000	$34,550,000
Capital Recovery Factor (CRF)	0.08581051722067				
Capex per year ($/yr)	**$29,647,534**	**$59,295,067**	**$118,590,135**	**$177,885,202**	**$296,475,337**
Total annual cost ($/yr)	**$33,102,534**	**$66,205,067**	**$132,410,135**	**$198,615,202**	**$331,025,337**
Levelized cost of energy ($/MWh)	**$141**	**$141**	**$141**	**$141**	**$141**

B.2.4 Avoided Transmission and Distribution Costs

Because TEP has deep insight into the health of the grid (that external observers do not have), they know what parts of the grid are the most congested. Accordingly, TEP could engage in a targeted deployment of rooftop solar to alleviate grid congestion in those areas. This could lead to high value of avoided/deferred T&D costs by deferring grid upgrades (substations, feeders, distribution lines).

Note this congestion can be modeled thoroughly with a probabilistic analysis across a variety of load scenarios.

Lacking insight into grid congestion and sophisticated computational tools, we employed assumptions of avoided cost for T&D. However, there is significant literature in this space, and we encourage TEP to consider a more in-depth analysis of avoided T&D costs. A more accurate analysis could yield savings much higher than what we found here, at the rate of multiple cents per kWh.

Relevant links:

- Real Reliability: The Value of Virtual Power
- Quantifying Distributed Solar Photovoltaics Costs and Benefits: Considerations and Decision Framework for Oklahoma
- Virtual Power Plants and Distributed Energy Resource Management Systems
- How much capacity deferral value can targeted solar deployment create in Pennsylvania?
- Avoided Cost of Transmission and Distribution Capacity Study
- Avoided Transmission and Distribution Costs Study - Draft Research Plans

Using the following assumptions:

Parameter	Value	Unit
Transmission avoided cost ($/kW-yr)	15	$/kW-yr
Distribution avoided cost ($/kW-yr)	35	$/kW-yr
Solar ELCC (peak contribution) (%)	30	%
Target solar capacity (% of peak)	5	%
Tucson peak load (MW)	2764	MW
kWh/year per kW installed (kWh/yr/kW)	1700	kWh/yr/kW
Annual energy (portfolio) (MWh/yr)	234,940.00	MWh/yr

We calculated the following:

Metric	Value	Unit
Target solar capacity (MW)	138.2	MW
Effective capacity for T&D (MW)	41.46	MW
Annual transmission avoided ($)	$621,900	$
Annual distribution avoided ($)	$1,451,100	$
TOTAL ANNUAL T&D AVOIDED ($)	**$2,073,000**	$
Annual MWh	234940	MWh/yr
Value per MWh ($/MWh)	$9	$/MWh

Which leads to an updated LCOE of:

Metric	Value	Unit
Previous LCOE ($/MWh)	$141	$/MWh
T&D avoided benefit ($/MWh)	$9	$/MWh
New Effective LCOE ($/MWh)	**$132**	$/MWh

B.2.5 Levelized Firming Cost

In its 2025 LCOE+ report, Lazard employed the following methodology to estimate the so-called "levelized firming cost". It multiplies the nameplate capacity of an intermittent energy resource by (1 - ELCC%) to estimate the amount of kW that is to be firmed. Then, it multiplies that by the Net Cost of New Entry (Net CONE), which is defined as capital and operating costs less expected market revenues for a new, firm resource (e.g., gas peaker or battery storage). Net CONE is established by the respective balancing authority. Then, it divides that by estimated mWh to get the rough cost of an LCOE that includes the cost of firming.

$$\frac{\text{Nameplate Capacity (kW)} \times (1 - \text{ELCC (\%)}) \times \text{Net CONE (\$/kW-month)} \times 12\text{ Months}}{\text{Nameplate Capacity (MW)} \times \text{Regional Capacity Factor (\%)} \times 8{,}760\text{ Hours}} = \text{Levelized Firming Cost (\$/MWh)}$$

Figure 2: Net CONE Formula from Lazard

Lazard calculated the levelized firming cost for some ISOs:

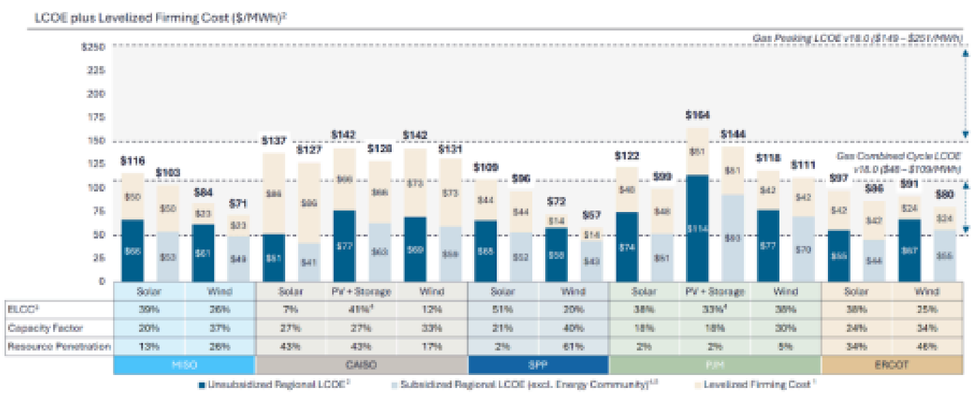

Figure 3: Net CONE values for different resources in different ISOs, as calculated by Lazard

As an illustrative example, we applied that methodology to Tucson. Lacking a Net CONE value (no such value is established for Arizona), we used a number close to CAISO's, which is $18.92/kW-month for firming an energy source with a 4-hour lithium-ion battery. All other ISOs employ a firming source of natural gas peaker, yielding much lower Net CONE values closer to $9-10/kW-month.

Using the following parameters:

Parameter	Value	Unit
Solar ELCC (peak contribution) (%)	30	%
Target solar capacity (% of Tucson peak)	5	% of Tucson peak
Net Cost of New Entry ($/kW-month)	$18	$/kW-month
Annual capacity factor (%)	31	%

We calculated the following:

Metric	Value	Unit
Target Nameplate Solar Capacity (kW)	138200	kW
Firm Solar Capacity (kW)	41460	kW
Non-Firm Solar Capacity (kW)	96740	kW
Numerator ($)	$20,895,840	$
Denominator (MWh)	375295.92	MWh
Levelized Firming Cost ($/MWh)	**$56**	$/MWh

Leading to an updated LCOE of:

Metric	Value	Unit
Previous LCOE ($/MWh)	$141	$/MWh
New LCOE ($/MWh)	**$197**	$/MWh

Note that this is illustrative, as a DCP rooftop solar deployment would not be done to deploy firm solar, but most likely instead to enable reduction of peak load (see section 5.3).

B.3 Storage-only analysis (LCOS)

B.3.1 Assumptions

Significant value can be obtained from conducting a DCP-style rollout of batteries, as it would enable TEP to flexibly control the morning and evening peaks. This would significantly lower peak grid usage, allowing for more economical dispatch of TEP's existing resources.

Note on federal incentives: This model does not capture the Investment Tax Credit (ITC) for standalone battery storage, which was preserved in the One Big Beautiful Budget Act (OBBBA). For utility-owned, rate-based BESS assets, the ITC would reduce effective CAPEX. The LCOS figures presented here are therefore conservative with respect to available federal incentives.

With these assumptions:

Parameter	Value	Unit
Battery capacity per home (kWh)	13.50	kWh
Battery duration (hours)	4.00	hours
Battery power rating per home (kW)	3.38	kW
Total installed cost ($/kWh)	500	$/kWh
Battery calendar lifetime (years)	15.00	years
Annual capacity degradation rate (%/yr)	2.0%	%/yr
Depth of discharge (DoD) (%)	100%	%
Round-trip efficiency -- RTE, AC-AC (%)	90%	%
Annual cycles (cycles/yr)	365	cycles/yr
Annual O&M (% of installed CAPEX/yr)	2.50%	%/yr
Charging electricity cost ($/MWh)	80.00	$/MWh
ELCC - 4-hour battery (%)	80.0%	%
Tucson peak load (MW)	2,764	MW
TEP ratepayers (#)	451,936	#

And these scenario assumptions:

Parameter	Value	Unit
Target firm battery capacity (% of Tucson peak)	5.0%	%
Discount rate (%)	7.0%	%

B.3.2 Baseline LCOS

We calculate the following:

Metric	Value	Unit
Target firm capacity (kW)	138,200	kW
Nameplate battery kW needed	172,750	kW
Homes needed (#)	51,185	#
Total installed capacity (kWh)	691,000	kWh
Total CAPEX ($)	$345,500,000	$
Annual usable energy per home -- Yr 1 (kWh/yr)	4,927.50	kWh/yr
Annual usable energy per home -- Yr 1 (MWh/yr)	4.93	MWh/yr
Annual portfolio energy -- Yr 1 (MWh/yr)	252,215	MWh/yr
Degradation adjustment factor	0.8714	-
Average annual portfolio energy (MWh/yr)	219,789	MWh/yr
Avg annual charging energy (MWh/yr)	244,210	MWh/yr
Annual charging cost -- avg ($/yr)	$19,536,828	$/yr
Annual O&M cost ($/yr)	$8,637,500	$/yr
Capital Recovery Factor (CRF)	0.1098	-
Annualized CAPEX ($/yr)	$37,934,043	$/yr
Total annual cost ($/yr)	$66,108,371	$/yr
LCOS ($/MWh)	**$301**	$/MWh
LCOS excl. charging cost ($/MWh)	$212	$/MWh

And using a crude method, as before, we calculate the following:

Annual cost per ratepayer ($/yr)	$146.28	$/yr
Monthly cost per ratepayer ($/month)	$12.19	$/mo

Note that this LCOS is estimated with a CRF. The full fiscal analysis includes a LCOS estimate using a full discounted cash flow method, but is not shown here. The more accurate DCF LCOS comes out to $296/MWh, a <2% difference.

B.3.3 Scenario Analysis

Similar to before, we calculate multiple different scenarios based off the % peak load that TEP wishes to meet with batteries:

	Low	Baseline	Medium	High	Very High
Target firm capacity (% of Tucson peak)	5.0%	10.0%	20.0%	30.0%	50.0%
Target firm capacity (kW)	138,200	276,400	552,800	829,200	1,382,000
Nameplate battery kW needed	172,750	345,500	691,000	1,036,500	1,727,500
Homes needed (#)	51,185	102,370	204,741	307,111	511,852
Total installed capacity (kWh)	691,000	1,382,000	2,764,000	4,146,000	6,910,000
Total CAPEX ($)	$345,500,000	$691,000,000	$1,382,000,000	$2,073,000,000	$3,455,000,000
Annual energy per home -- Yr 1 (kWh/yr)	4,927.50	4,927.50	4,927.50	4,927.50	4,927.50
Annual portfolio energy -- Yr 1 (MWh/yr)	252,215	504,430	1,008,860	1,513,290	2,522,150
Avg annual portfolio energy (MWh/yr)	219,789	439,579	879,157	1,318,736	2,197,893
Annual O&M cost ($)	$8,637,500	$17,275,000	$34,550,000	$51,825,000	$86,375,000
Annual charging cost -- avg ($)	$19,536,828	$39,073,656	$78,147,311	$117,220,967	$195,368,278
Annualized CAPEX ($/yr)	$37,934,043	$75,868,086	$151,736,171	$227,604,257	$379,340,428
Total annual cost ($/yr)	$66,108,371	$132,216,741	$264,433,482	$396,650,224	$661,083,706
LCOS ($/MWh)	**$301**	**$301**	**$301**	**$301**	**$301**

B.3.4 Avoided T&D with Batteries

Similar to before, we calculate avoided T&D with batteries.

With these assumptions:

Parameter	Value	Unit
Transmission avoided cost ($/kW-yr)	15	$/kW-yr
Distribution avoided cost ($/kW-yr)	35	$/kW-yr
Battery ELCC (%)	80.0%	%
Target battery capacity (% of peak)	5.0%	%

Tucson peak load (MW)	2,764	MW
Avg annual portfolio energy (MWh/yr)	219,789	MWh/yr

We calculate the following:

Metric	Value
Target nameplate battery capacity (kW)	172,750
Effective capacity for T&D (kW)	138,200
Annual transmission avoided ($)	$2,073,000
Annual distribution avoided ($)	$4,837,000
TOTAL ANNUAL T&D AVOIDED ($)	**$6,910,000**
Value per MWh ($/MWh)	$31

Leading to an updated LCOS:

Metric	Value	Unit
Previous LCOS ($/MWh)	$301	$/MWh
T&D avoided benefit ($/MWh)	$31	$/MWh
New Effective LCOS ($/MWh)	**$269**	$/MWh

B.4 Blended Solar + Storage

B.4.1 Combined Assumptions

We also calculate the blended LCOS of a rollout that includes both solar + storage.

With these solar assumptions:

Parameter	Value	Unit
Solar system size per home (kW)	6	kW
kWh/yr per kW installed (kWh/yr/kW)	1,700	kWh/yr/kW
Solar installation cost ($/W)	2.50	$/W
Solar system lifetime (years)	25	years

Solar annual O&M (% of capex)	1.0%	%/yr
Solar ELCC (%)	30.0%	%
Solar discount rate (%)	7.0%	%
Solar LCOE -- companion model ($/MWh)	141	$/MWh

And these battery assumptions:

Parameter	Value	Unit
Battery capacity per home (kWh)	13.50	kWh
Installed cost per kWh ($/kWh)	$500.00	$/kWh
Battery lifetime (years)	15.00	years
Battery ELCC (%)	80.0%	%
Battery discount rate (%)	7.0%	%
Avg annual energy per home -- battery (MWh/yr)	4.29	MWh/yr
Battery CRF	0.1098	--
Battery annual O&M per home ($/yr)	$168.75	$/yr

B.4.2 Baseline Blended LCOE/LCOS

We calculate the following:

Metric	Value	Unit
Solar CAPEX per home ($)	$15,000	$/home
Battery CAPEX per home ($)	$6,750	$/home
Total CAPEX per home ($)	$21,750	$/home
Annual solar energy per home (MWh/yr)	10.20	MWh/yr
Battery charged from solar? (0=No, 1=Yes)	1	binary
Annual battery energy per home (MWh/yr)	4.29	MWh/yr
Annual solar O&M per home ($/yr)	$150.00	$/yr
Solar CRF	0.0858	--
Annualized solar CAPEX per home ($/yr)	$1,287.16	$/yr
Annualized battery CAPEX per home ($/yr)	$741.11	$/yr
Annual battery O&M per home ($/yr)	$168.75	$/yr
Battery charging cost per home ($/yr)	-	$/yr

Total solar annual cost per home ($/yr)	$1,437.16	$/yr
Total battery annual cost per home ($/yr)	$909.86	$/yr
Combined annual cost per home ($/yr)	$2,347.02	$/yr
Solar LCOE per this model ($/MWh)	$141	$/MWh
Battery LCOS -- solar-charged ($/MWh)	$212	$/MWh
Battery LCOS -- grid-charged ($/MWh)	$301	$/MWh
Blended LCOE -- solar+storage ($/MWh)	**$230**	$/MWh
Effective ELCC -- solar+storage combined (%)	48.0%	%

B.4.3 Scenario Analysis

We present a range of scenarios based off the % peak that TEP wishes to meet:

	Low Penetration	Baseline	Medium	High	Very High
Target capacity (% of Tucson peak)	5.00%	10.00%	15.00%	20.00%	25.00%
Target at-peak capacity (kW)	138,200	276,400	414,600	552,800	691,000
Solar dependable at-peak capacity per home (kW)	1.80	1.80	1.80	1.80	1.80
Battery dependable at-peak capacity per home (kW)	2.70	2.70	2.70	2.70	2.70
Combined dependable at-peak capacity per home (kW)	4.50	4.50	4.50	4.50	4.50
Homes needed (#)	30,711	61,422	92,133	122,844	153,556
Solar CAPEX per scenario ($)	$460,666,667	$921,333,333	$1,382,000,00 0	$1,842,666,6 67	$2,303,333 ,333
Battery CAPEX per scenario ($)	$207,300,000	$414,600,000	$621,900,000	$829,200,00 0	$1,036,500 ,000
Total CAPEX ($)	$667,966,667	$1,335,933,333	$2,003,900,00 0	$2,671,866,6 67	$3,339,833 ,333
Annual solar energy (MWh/yr)	313,253	626,507	939,760	1,253,013	1,566,267
Annual battery energy -- avg (MWh/yr)	131,874	263,747	395,621	527,494	659,368
Annual solar O&M ($)	$4,606,667	$9,213,333	$13,820,000	$18,426,667	$23,033,33 3
Annual battery O&M ($)	$5,182,500	$10,365,000	$15,547,500	$20,730,000	$25,912,50

					0
Annualized solar CAPEX ($)	$39,530,045	$79,060,090	$118,590,135	$158,120,180	$197,650,225
Annualized battery CAPEX ($)	$22,760,426	$45,520,851	$68,281,277	$91,041,703	$113,802,129
Total annual cost ($)	**$72,079,637**	**$144,159,275**	**$216,238,912**	**$288,318,549**	**$360,398,187**
Blended LCOE -- solar+storage ($/MWh)	**$230**	**$230**	**$230**	**$230**	**$230**
Solar-only LCOE for reference ($/MWh)	$141	$141	$141	$141	$141
Battery LCOS -- solar-charged ref ($/MWh)	$212	$212	$212	$212	$212

B.5 Comparison vs. industry benchmarks

B.5.1 LCOE from Different Sources

Additionally, we establish a comparison table of LCOEs of different energy sources (from Lazard's 2025 LCOE+ Report)

SCENARIOS BY ENERGY SOURCE	
Energy Source	**(LCOE, $/MWh)**
DCP Solar (this model)	$141
Rooftop Solar	$122-284
Combined Cycle Gas	$48-109
Gas Peaker	$149-251
Coal	$71-173

While rooftop solar is more expensive than combined cycle gas for baseload, we are currently considering solar to be used for peak load. In this instance, it is clear that the LCOE of rooftop solar is more economical than using a Gas Peaker plant.

B.5.2 LCOE/LCOS from Different Sources

Technology / Scenario	LCOS Low ($/MWh)	LCOS High ($/MWh)	LCOS Mid ($/MWh)
Utility-Scale Li-Ion, 4-hr	$115	$254	$185
C&I Li-Ion, 1 hr	$319	$506	$413
Residential Li-Ion, 4-hr	$547	$860	$704

THIS MODEL -- Utility-Owned Residential (grid-charged, Baseline scenario)	$301	$301	**$301**
THIS MODEL -- Utility-Owned Residential (solar-charged, excl. charging cost)	$212	$212	**$212**

Technology	LCOE Low ($/MWh)	LCOE High ($/MWh)	LCOE Mid ($/MWh)
Rooftop Solar - Community and C&I	$81	$217	$149
Combined Cycle Gas (Lazard 2025)	$48	$109	$79
Gas Peaker (Lazard 2025)	$149	$251	$200
Coal (Lazard 2025)	$71	$173	$122
THIS MODEL -- Solar LCOE (companion)	$141	$141	**$141**
THIS MODEL -- Blended Solar+Storage	$230	$230	**$230**

B.6 Sensitivity Analysis

The full fiscal model contains a sensitivity analysis of the following variables:

1. Sensitivity to Installed Cost ($/kWh)
2. Sensitivity to Discount Rate (%)
3. Sensitivity to Annual Cycles (cycles/yr)
4. Sensitivity to Battery Lifetime (years)
5. Sensitivity to Charging Cost ($/MWh)
6. Sensitivity to Annual Degradation Rate (%)

B.7 What this Model Does Not Capture

B.7.1 Notes and Deficiencies

This is an illustrative, albeit technically-rooted fiscal analysis. This is not a full system-wide cost-benefit comparison. The hope is for TEP to consider these numbers and retain a consultant to conduct a rigorous, in-depth fiscal analysis that employs more sophisticated methodology and computing power.

TEP should additionally consider integration costs, backup capacity, curtailment costs.

These are just some of the deficiencies of this analysis; more are mentioned throughout the report:

- Lacks locational granularity for T&D analysis (avoided cost values vary by feeder location; TEP would target high-value areas)
- Does not consider interactions with WEIM
    - TEP can conduct energy arbitrage with batteries, enabling profit by, for example, buying excess solar from CA for cheap in the day and selling in the evening for profit
- Does not consider future interactions with SPP Markets+
- Does not consider VPP value in an ancillary services market
- Does not conduct sensitivity analysis for avoided T&D costs

B.7.2 Ancillary Services When Aggregated as a Virtual Power Plant

In ISO/RTO markets, rooftop solar can provide significant ancillary benefits when aggregated and controlled as Virtual Power Plant (VPP). This includes frequency regulation and reactive power revenue.

TEP, being a vertically-integrated, regulated monopoly, does not have such a wholesale, capacity, or ancillary services (AS) market. As such, we did not model the possibly ancillary value of a VPP; however, there are numerous ways in which a solar+storage VPP could provide value to TEP.

First, TEP participates in the California Independent System Operator (CAISO)'s Western Energy Imbalance Market (WEIM), a real-time energy-only market that economically dispatches resources every 5 minutes across the West. By changing TEP's net load shape and providing controllable flexibility, even without an AS market, **a DCP-enabled VPP can enhance TEP's WEIM position**, enabling reduction of costly imports in tight hours and additional low-cost exports in surplus hours.

Second, **TEP is set to join the Southwest Power Pool (SPP)'s Markets+ in early 2027**. This will integrate TEP into a capacity market and open up possible opportunities for revenue from ancillary services.

Third, **even without a formal AS market, VPPs provide significant benefits**. TEP has already built on a mini-VPP through their smart thermostat program, although it is only limited to demand response in peak hours. By aggregating rooftop solar (and possibly battery storage, not modeled here) as a VPP, TEP can avail itself of a **firm** resource that it can use to shape load curves. For instance, TEP could dispatch the VPP to match peak load during the day and particularly the evening hours.

Not only does this move TEP closer towards having enough grid control to enable a 24/7 clean energy system eventually, but by enabling TEP to control and reduce peak load, TEP can safely increase energy demand on the grid for the rest of the hours of the day without compromising reliability. By increasing load on the grid in the rest of the day, the fixed costs of the grid can be spread out to more users and more hours, **thereby placing downward pressure on energy prices**.

Appendix C. Western Electricity Markets and TEP's Position

C.1 Definitions: ISOs, RTOs, FERC

The Federal Energy Regulatory Commission (FERC) is the independent federal agency that regulates the interstate transmission of electricity, natural gas, and oil. FERC oversees wholesale electricity markets -- transactions in which power is bought and sold in bulk between generators, utilities, and other market participants before it reaches retail customers [81]. FERC does not regulate retail electricity rates (what customers pay on their monthly bills) -- that is the domain of state utility commissions like the ACC.

An Independent System Operator (ISO) is an organization, often a nonprofit, formed at the direction or recommendation of FERC, that coordinates, controls, and monitors the operation of the electrical power system, usually within a single U.S. state or a small group of states. ISOs have independent authority -- overseen by FERC -- to operate transmission lines owned by utilities. The "independent" designation means the ISO is structurally separated from the generators and utilities whose assets it coordinates, preventing conflicts of interest [82].

A Regional Transmission Organization (RTO) is similar to an ISO but typically covers a larger geographic area -- often spanning multiple states -- and has a more explicitly defined set of minimum characteristics and functions established by FERC's Order No. 2000. RTOs manage the transmission grid and operate competitive wholesale electricity markets across their footprints. The key difference between an ISO and an RTO is largely one of scale and formal FERC designation, and in common usage the terms are often used interchangeably.

Both ISOs and RTOs are nonprofit entities that:

- Manage the physical operation of the high-voltage transmission grid in real time (dispatching power plants to match supply and demand every few seconds)
- Operate competitive wholesale electricity markets (day-ahead and real-time energy markets, capacity markets, and ancillary services markets)
- Plan for long-term transmission infrastructure needs
- Ensure compliance with reliability standards set by NERC (the North American Electric Reliability Corporation)

Roughly two-thirds of the electricity consumed in the United States flows through RTO/ISO-managed markets. The remainder, including most of the Western United States, operates under a more traditional bilateral trading model, where utilities transact directly with each other rather than through a centralized market.

C.2 Major U.S. ISOs and RTOs

1. **ERCOT** (Electric Reliability Council of Texas)

Texas's deregulated market serves approximately 25 million customers and about 90% of the state's load [83]. ERCOT operates as an ISO.

2. **CAISO** (California Independent System Operator)

California partially deregulated its electricity market in the 1990s, leading to the infamous California energy crisis of 2000-2001, during which Enron and other energy traders manipulated the wholesale market, causing rolling blackouts and spiking prices. California subsequently re-regulated significant portions of its market while retaining a competitive wholesale structure managed by CAISO [82]. California's electricity market is partially deregulated: large commercial and industrial customers can choose suppliers, but residential customers are served by regulated utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric) that purchase power in the wholesale market that CAISO administers.

3. **ISO-NE** (Independent System Operator New England)

ISO-NE operates the transmission grid and competitive wholesale electricity markets for the six New England states (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont). Although it has ISO in the name, ISO-NE is technically an RTO.

4. **PJM Interconnection** (PJM)

PJM is the largest RTO in the United States, operating the high-voltage transmission system and wholesale electricity markets across all or parts of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia) and the District of Columbia [84].

C.3 The Western Energy Imbalance Market (WEIM)

The Western Energy Imbalance Market (WEIM) is a regional market operating across the Western Interconnection. It is a real-time energy market (not a day-ahead market) operated by CAISO that allows participating utilities to buy and sell small amounts of electricity to balance supply and demand every five minutes across a wide geographic area, taking advantage of the diversity of renewable energy resources (wind in Wyoming, solar in Arizona, hydropower in the Pacific Northwest) to reduce costs and improve reliability.

The WEIM launched in 2014 and has grown to include 22 balancing authorities across 11 western states, representing approximately 80% of electricity demand in the Western

Interconnection [85]. Total estimated benefits across all WEIM participants have exceeded $7.82 billion since the market launched [85].

Notably, Arizona Public Service (APS), Tucson Electric Power (TEP), and Salt River Project (SRP), already participate in the WEIM.

The WEIM, however, is only a real-time balancing market -- it does not provide the more comprehensive market services (day-ahead scheduling, capacity markets, ancillary services) that Eastern ISOs like PJM offer. This limits its ability to fully optimize how the Western grid plans for and integrates large amounts of variable renewable energy.

C.4 SPP Markets+

The Southwest Power Pool (SPP) is an RTO that currently manages the transmission grid and wholesale electricity markets primarily in the central United States (including Oklahoma, Kansas, Nebraska, the Dakotas, and parts of surrounding states).

In recent years, SPP has developed a new market product specifically designed for the Western Interconnection: Markets+, a day-ahead and real-time unit commitment and dispatch market intended to bring more comprehensive market coordination to utilities in the West.

Unlike the WEIM -- which is only a real-time balancing market and is governed by CAISO (a California entity) -- Markets+ would provide a full day-ahead market, enabling utilities to schedule generation commitments 24 hours in advance and capturing the significant efficiency gains that come from day-ahead optimization of a geographically diverse generation fleet. Markets+ is also governed by an independent entity rather than being operated by a single state's utility.

Four Arizona utilities have committed to join SPP's Markets+ when it launches in 2027: APS, TEP, SRP, and UNS [86]. This represents a major step toward deeper market integration for Arizona. The market is expected to bring "almost $100 million above current market participation" in additional benefits to participating utilities [87].

C.5 What These Market Structures Mean for DCP

The existence of the WEIM and the coming Markets+ market are relevant to DCP for several reasons.

First, they establish that Arizona utilities are not isolated actors -- they operate within increasingly interconnected western energy markets, buying and selling power based on real-time and day-ahead prices.

Second, a well-designed DCP program that deploys distributed solar + storage at scale can interact with these markets: TEP's distributed storage fleet, for example, could participate in real-time market signals from the WEIM or Markets+ to charge when regional power is cheap (midday solar surplus) and discharge when power is expensive (late afternoon/early evening peak demand).

Third, Arizona's participation in broader western markets means the value of local distributed clean energy assets extends beyond Tucson -- it reduces the need for TEP to purchase expensive peak power from regional markets, lowering costs for ratepayers.

Appendix D. Case Studies

D.1 Concerns with Xcel Energy Capacity*Connect

Xcel's Capacity*Connect plan has received some opposition and pushback for varied reasons. It is with nothing that some of these concerns are not applicable in Arizona due to the difference in market design. More about these concerns, as well as Xcel's response to them, can be seen in [88].

We also would like to bring attention to a comment by Pier LaFarge about the hidden benefits of utility-owned grid assets. The full comment can be seen in [89], with some notable excerpts here:

"The regulated utility return is fixed, which limits downside, but also caps upside. Every dollar of grid value above the regulated utility return (say 9%) gets socialized to the benefit of all the ratepayers in the state. …
"The companies that offer third-party financing for DER assets aren't regulated. Their upside is not capped. They do not share the benefits of any upside with ratepayers. They keep every dollar above their target return. If there's [a] downside, the company loses money, but the project doesn't get a single dollar cheaper for the grid. …
"Would you rather have the enormous value batteries create for the grid go into the pockets of private, unregulated companies, or get shared to the benefit of everyone paying for power in the state? That's the system of shared benefit that utility ownership delivers."

D.2 Green Mountain Power

Green Mountain Power in Vermont launched two battery programs in 2020: a utility-owned lease program and a customer-owned Bring-Your-Own-Device program.

About 2,500 customers have signed up for the leasing program, which totals about 22 MW, according to the PUC's decision. Under the program, customers lease two Tesla Energy Storage systems for 10 years. A waitlist for the program exceeds 1,000 customers.

Nearly 200 customers are enrolled in the BYOD program, and GMP expects 100 customers will enroll over the rest of this year, according to the PUC decision.

The utility-led lease model enrolled 10 times more people than the BYOD program, providing the strongest evidence that utility-led deployment dramatically outpaces consumer-directed approaches [90].

D.3 Brooklyn-Queens

The Con Edison Brooklyn-Queens Demand Management program demonstrated that spending up to $200 million on DERs could avert building a $1 billion substation, reducing peak demand by 52 MW The New York Public Service Commission extended the program indefinitely, declaring "what was new has become normal" [55].

D.4 Arizona Public Service

Arizona Public Service's "Cool Rewards" demand response program has enrolled 83,000+ smart thermostats with 145 MW of load-shedding capacity [91].

D.5 Maryland BESS Pilot Program

Following Xcel Energy's Capacity*Connect filing, Baltimore Gas & Electric (BGE) became the first utility to replicate the DCP model in a separate regulatory jurisdiction. In November 2025, BGE filed a 15 MW Customer-Sited Program (CSP) with the Maryland Public Service Commission pursuant to the Next Generation Energy Act (NGEA) of 2025, using Capacity*Connect as its explicit programmatic template. The MD PSC advanced the program in Order No. 92281, Case No. 9715 [63].

The program is entirely utility-owned and utility-operated. The initial 15 MW tranche is designed primarily for targeted distribution system peak shaving and participation in PJM wholesale markets. A second procurement filing expanding the program is expected in November 2026 [63].

This is directly relevant to the TEP case. It demonstrates that Capacity*Connect is a replicable template, not a Minnesota-specific outcome -- it has already been adopted across a different RTO (PJM vs. MISO) and a different regulatory jurisdiction within months of the original filing.

Appendix E. TEP Program and Regulatory History

E.1 Past TEP Solar Initiatives

E.1.1 Bright Tucson Community Solar

One of TEP's first large scale solar projects consists of the Bright Tucson Community Solar (BTCS) program, in which customers buy solar in 150 kWh blocks, each block costing $3, and this cost is added to their monthly electric bill.

The program, created in 2011, soon reached large amounts of popularity, exceeding TEP's own expectations (1.6 MW built by 2014).

This may in part be due to the fixed cost of $3 for 20 years, protecting against price increases, and the fact that the blocks were exempt from common energy taxes like the Renewable Energy Standard Tariff (REST) and Purchased Power and Fuel Adjustment Clause (PPFAC). In addition to this, consumers could drop out of the program at any time free of charge.

This program has been rebranded and is now known as the GoSolar Shares program, with the only change being that the cost of each block is now $1.50 [92,93].

E.1.2 GoSolar Home

GoSolar Home is a solar initiative created by TEP designed for residential customers only. Customers utilize energy from a 12.5 MW solar grid in Southeast Tucson called Raptor Ridge, therefore not needing any rooftop installation.

The monthly rate being paid depends on the previous year's average electricity usage, and remains fixed for 10 years (unless annual usage varies by more than 15%). Requirements for participants include using TEP for at least a year with a good payment history.

However, TEP has reached their enrollment goal for this program, which means GoSolar Shares serves as the current alternative [94].

E.1.3 GoSolar Shares

GoSolar Shares, consists of the same elements of BTCS except the price of each kWh share is now $1.50 instead of $3. It is the current alternative to GoSolar Home and serves residential and commercial customers under different pricing plans.

Share prices must be paid each month even if usage does not align with shares bought. However, the cost of excess solar energy is carried over to the next billing period as credit.

Benefits include availability for people not eligible for other solar options and the lack of installment costs. In addition, consumers can choose how much of their energy they want solar to cover.

E.1.4 Net Metering and Resource Comparison Proxy

In 2017, the ACC, composed of 5 Republicans serving four-year terms, voted to phase out net metering for new customers [95]. They also ruled that utilities must "develop five-year cost avoidance analyses based on conventional production, to determine the … rates provided to consumers."

Although TEP continues to utilize rooftop solar, their original Residential Solar Program created in 2014, which gave TEP ownership of DERs such as solar panels, has been discontinued. TEP does not endorse or partner with solar installment companies but does issue Permission to Operate for residential solar systems installed by local installers [96].

Currently, TEP uses a Resource Comparison Proxy (RCP) or net billing rate, which provides compensation for excess electricity returning to the grid. This is about $0.057 per kWh compared to the full (discontinued) net metering rate of around $0.15 per kWh [97]. The RCP rate is calculated using the 5 year average cost of large scale utility solar generation. The RCP rate changes gradually, but customers can lock in the same rate for 10 years once approved [98].

E.1.5 TEP Residential Solar Program

The Renewable Energy Standard and Tariff (REST) was approved and passed by the ACC in 2006, and declared that electric utilities in Arizona must source 15% of their electricity from renewable resources by 2025 [78].

As required by the REST program, TEP files annual implementation plans with the ACC [99]. As part of its 2015 REST implementation plans, in 2014, TEP formally proposed a residential rooftop solar program that would account for 3.5 MW of rooftop solar. As part of the program, customers would pay a $250 one-time fee for installation then have a fixed monthly rate for 25 years, protecting against price hikes. The panels would be directly installed and owned by TEP with the help of local installers [100].

The Residential Solar program was approved by the ACC in December 2014 and solar was limited to about 600 rooftops (upon ACC orders) with rates providing 3rd party cost parity.

In 2015, David Hutchens, the CEO of TEP, planned to double the size of the program due to its popularity. This was controversial and was not approved by the ACC [70,101]. TEP switched its focus to other solar initiatives around this time.

E.2 ACC Political Makeup

The ACC is a five-member body, elected statewide in partisan elections, that oversees public utilities including electric, gas, and water companies. The ACC holds authority over the rates utilities charge, the investments they make, the territories they serve, and the rules under which they interconnect with other energy sources [102]. Uniquely among Public Utility Commissions, the ACC is constitutionally established -- its existence and basic powers are written directly into the Arizona Constitution (Article 15), giving it a degree of independence from the legislature that utility commissions in many other states do not have.

Per Arizona state laws, the ACC regulates TEP by approving solar rates and renewable energy standards. The ACC has made several decisions which have significantly impacted the state of solar energy in Tucson.

To gain insight into these actions, it is key to review the political makeup of ACC members from the start of large-scale solar initiatives to the present year. It is important to note that the decisions made by ACC about TEP's programs, clean energy standards, etc **are not decisions based purely on merit -- they are heavily influenced by ideological and political views**, and all ACC actions should be viewed through that lens.

The following list consists of the five elected commissioners in the ACC from 2011 to 2026 and their political affiliations [76].

Year(s)	Chairman (party)	Other commissioners (party)	R/D split
2011	Gary Pierce (R)	Bob Stump (R); Sandra Kennedy (Dem; Paul Newman (D); Brenda Burns (R)	3 R / 2 D
2012–2014	Bob Stump (R)	Brenda Burns (R); Bob Burns (R); Gary Pierce (R); Susan Bitter Smith (R)	5 R / 0 D

2015	Susan Bitter Smith (R)	Bob Stump (Rep; Doug Little (R); Bob Burns (R); Tom Forese (R)	5 R / 0 D
2016	Doug Little (R)	Bob Stump (Rep; Bob Burns (R); Andy Tobin (R); Tom Forese (R)	5 R / 0 D
2017	Tom Forese (R)	Bob Burns (R); Doug Little (R); Andy Tobin (R); Boyd Dunn (R)	5 R / 0 D
2018	Tom Forese (R)	Bob Burns (R); Andy Tobin (R); Boyd Dunn (R); Justin Olson (R)	5 R / 0 D
2019–2020	Bob Burns (R)	Andy Tobin (R); Boyd Dunn (R); Justin Olson (R); Sandra Kennedy (D)	4 R / 1 D
2021–2022	Lea Márquez Peterson (R)	Sandra Kennedy (D); Anna Tovar (D); Justin Olson (R); Jim O'Connor (R)	3 R / 2 D
2023–2024	Jim O'Connor (R)	Lea Márquez Peterson (R); Anna Tovar (D); Kevin Thompson (R); Nick Myers (R)	4 R / 1 D
2025	Kevin Thompson (R)	Lea Márquez Peterson (R); Nick Myers (R); Rachel Walden (R); Rene Lopez (R)	5 R / 0 D

2026	Nick Myers (R)	Lea Márquez Peterson (R); Kevin Thompson (R); Rachel Walden (R); Rene Lopez (R)	5 Rep / 0 D

Glossary of Acronyms

1. ACC - Arizona Corporation Commission
2. AI - Artificial Intelligence
3. APS - Arizona Public Service
4. AS - Ancillary Services
5. BESS - Battery Energy Storage System
6. BGE - Baltimore Gas & Electric
7. BTCS - Bright Tucson Community Solar
8. BTM - Behind-the-Meter
9. BYOD - Bring Your Own Device
10. CAISO - California Integrated System Operator
11. CAPEX - Capital Expenditure
12. CCA - Community Choice Aggregation
13. CCE - Community Choice Energy
14. CCES - Commission on Climate, Energy, and Sustainability
15. CCN - Certificate of Convenience and Necessity
16. CEO - Chief Executive Officer
17. C&I - Commercial and Industrial
18. CONE - Cost of New Entry
19. CPI - Consumer Price Index
20. CPUC - California Public Utilities Commission
21. CRF - Capital Recovery Factor
22. CSP - Customer-Sited Program
23. DAC - Disadvantaged Community
24. DCF - Discounted Cash Flow
25. DCP - Distributed Capacity Procurement
26. DER - Distributed Energy Resource
27. DERMS - Distributed Energy Resource Management System
28. DoD - Depth of Discharge
29. DOE - Department of Energy
30. ECA - Energy Collaboration Agreement
31. ELCC - Effective Load Carrying Capability
32. EPC - Engineering, Procurement, and Construction
33. ERCOT - Electric Reliability Council of Texas
34. EV - Electric Vehicle
35. FERC - Federal Energy Regulatory Commission
36. GMP - Green Mountain Power
37. GW - Gigawatt
38. IEA - International Energy Agency

39. IOU - Investor-Owned Utility
40. IRP - Integrated Resource Plan
41. ISO - Independent System Operator
42. ISO-NE - Independent System Operator New England
43. ITC - Investment Tax Credit
44. LACE - Levelized Avoided Cost of Electricity
45. LADWP - Los Angeles Department of Water and Power
46. LBNL - Lawrence Berkeley National Laboratory
47. LCOE - Levelized Cost of Energy/Electricity
48. LCOS - Levelized Cost of Storage
49. MISO - Mid-Continent Independent System Operator
50. MPUC - Minnesota Public Utilities Commission
51. M&V - Measurement and Verification
52. MW - Megawatt
53. NERC - North American Electric Reliability Corporation
54. Net CONE - Net Cost of New Entry
55. NGEA - Next Generation Energy Act
56. NPV - Net Present Value
57. NREL - National Renewable Energy Laboratory
58. NWA - Non-Wires Alternative
59. NYISO - New York Independent System Operator
60. O&M - Operations and Maintenance
61. OBBBA - One Big Beautiful Budget Act
62. PJM - Pennsylvania, New Jersey, Maryland Interconnection
63. PPFAC - Purchased Power and Fuel Adjustment Clause
64. PRM - Planning Reserve Margin
65. PSC - Public Service Commission
66. PUC - Public Utilities Commission
67. PV - Photovoltaic
68. RCP - Resource Comparison Proxy
69. REST - Renewable Energy Standard and Tariff
70. REV - Reforming the Energy Vision
71. RFI - Request for Information
72. RMI - Rocky Mountain Institute
73. RTE - Round-Trip Efficiency
74. RTO - Regional Transmission Organization
75. SCADA - Supervisory Control and Data Acquisition
76. SCE - Southern California Edison
77. SEPA - Smart Electric Power Alliance
78. SMUD - Sacramento Municipal Utility District

79. SPP - Southwest Power Pool
80. SRP - Salt River Project
81. T&D - Transmission and Distribution
82. TEP - Tucson Electric Power
83. TFS - Technicians for Sustainability
84. TWh - Terawatt-hour
85. UNS - UNS Energy
86. VPP - Virtual Power Plant
87. WEIM - Western Energy Imbalance Market

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