


A GUIDE TO ENERGY IN ARIZONA

ARIZONA PIRG EDUCATION FUND

FALL 2020



Acknowledgments

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Please note the Arizona PIRG Education Fund and organizations in this guide do not necessarily work on or are represented by materials which do not directly state their name.

With public debate around important issues often dominated by special interests pursuing their own narrow agendas, the Arizona PIRG Education Fund offers an independent voice that works on behalf of the public interest. The Arizona PIRG Education Fund, a 501(c)(3) organization, works to protect consumers and promote good government. We investigate problems, craft solutions, educate the public, and offer Arizonans meaningful opportunities for civic participation. For more information about the Arizona PIRG Education Fund or for copies of this report, please visit www.arizonapirgedfund.org, email info@arizonapirg.org, or call us at (602)252-9227.

A Guide to Energy in Arizona was assembled by Marites Velasquez with Public Interest GRFX. The cover was designed by Caryn Potter of the Southwest Energy Efficiency Project (SWEEP).

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Introduction

Arizona is said to have something for everyone: cold snowy mountains and a hot desert climate; Native American lands, rural communities, and vibrant urban centers; well-renowned universities and trade schools; international attractions including the Grand Canyon and Hoover Dam as well as national sports teams, and local arts, cultural and ethnic celebrations.

As Arizonans, we are often known for our independent spirit. And when it comes to energy policy, Republican and Democrat policymakers in our state have worked together to put Arizona on a path to a more energy-efficient and a cleaner energy future. Now Arizonans across the political spectrum want government officials to take the necessary next steps on the route to an energy system that will reliably meet the demands of our growing and diverse population; protect consumer pocketbooks; and provide air quality and public health benefits.

The good news is that like our state, the clean energy sector provides something for everyone: energy efficient products and programs save consumers money on our monthly electric bills; farmers reap economic gains through the placement of wind turbines on their land; solar companies put the sun to work and provide good paying jobs to Arizonans; and private sector and utilities install electric vehicle charging stations to connect us both in-and-outside of Arizona.

In recent years, technological improvements have contributed to a more efficient and cleaner power grid. Solar energy costs have dramatically declined; storage for electricity is becoming widely available and cost effective; and the number of electric vehicle manufacturers and models has increased. Furthermore, electric utilities are collaborating more closely, providing opportunities for energy independence, reliability improvements for the electric system, and cost savings for consumers.

A Guide to Energy in Arizona is intended to provide elected and government officials, business and organizational leaders, members of the media, and Arizonans with a primer on energy issues in our state. *A Guide to Energy in Arizona* highlights key research and components of reports, it is not an exhaustive compilation. As energy issues continue to evolve, we encourage you to use the contact list contained at the end of this document to learn more about energy trends and policies.

Background

Arizona Is In A Major Energy Transition

- **All major electric utilities have set clean energy goals to reduce carbon emissions.**
  - APS has a goal of 45% renewable energy by 2030 and 100% clean energy (includes nuclear) by 2050.
  - TEP's goal is 70% power from renewable resources while reducing carbon dioxide emissions 80% by 2035.
  - SRP's goal is to reduce the amount of CO2 emitted by 62% from 2005 levels by 2035 and by 90% by FY 2050.

- **Wind and solar resources are now less expensive than fossil generation causing an economic shift for utilities.**
  - All coal plants in or feeding the state are expected to close, as they are no longer economic compared to new resources.
  - Gas, the primary electricity power source for Arizona, will be replaced, over time, with clean energy.
  - Hybrid power plants (battery storage combined with wind and solar) can perform any function of gas with higher reliability and lower costs.

- **Electrification of the transportation sector creates opportunities for the state.**
  - Several major truck and auto electric vehicle (EV) manufactures have located in the state.
  - EVs can help address ozone air pollution problems in metro areas.
  - EVs, and to a lesser extent hydrogen vehicles, are an innovation sector and job creator for Arizona.

- **The state and consumers would benefit from a greater focus on shaping and controlling energy use, rather than building new power plants, but policy is necessary.**
  - Lowest cost resources available, energy efficiency, will not be maximized without direction to utilities.
  - Utility resource sharing and greater cooperation though wholesale market development can greatly improve reliability and reduce consumer costs but adoption by utilities is slow.
  - Utilities are not keeping pace with consumer demand for services, causing unnecessary costs.

- **Social issues are increasing in importance.**
  - The state has not addressed the significant impacts of fossil plant closure on communities and Arizonans.
  - Electricity costs are becoming a greater burden for an increasing percent of the population.
  - Policies to provide certainty are not keeping up with the pace of change.

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

BOB BURNS, Chairman
BOYD DUNN
SANDRA D. KENNEDY
JUSTIN OLSON
LEA MÁRQUEZ PETERSON

IN THE MATTER OF POSSIBLE MODIFICATIONS TO THE COMMISSION'S ENERGY RULES	)))))	**DOCKET NO. RU-00000A-18-0284** **Joint Stakeholder Proposal for New Energy Rules—Second Filing**

I. Introduction

On July 30th, 2019, twenty-five organizations filed a comprehensive vision for Arizona's energy future.[1] Those organizations include American Council for an Energy-Efficient Economy, Arizona Faith Network, Arizona Interfaith Power and Light, Arizona Solar Energy Industries Association (AriSEIA), Arizona Public Health Association, Black Mesa Water Coalition, CHISPA Arizona, Conservative Alliance for Solar Energy (CASE), Diné C.A.R.E., E4TheFuture, Elders Climate Action, Environment Arizona Research & Policy Center, Natural Resources Defense Council, Our Mother of Sorrows Catholic Church, Physicians for Social Responsibility, Sierra Club, Solar Energy Industries Association (SEIA), Solar United Neighbors, Southwest Energy Efficiency Project (SWEEP), Sunrun, Tó Nizhóní Ání, Tucson 2030 District, Vote Solar, Western Grid Group, and Western Resource Advocates (WRA). As of the date of this filing, this proposal has received additional support from the following organizations: Grand Canyon Trust, Yavapai Climate Change Coalition, Oculus-Studio, League of Women Voters Arizona, Solar Gain and the Earth Justice Ministry of Unitarian Universalist Congregation of Phoenix. In total, thirty-two organizations, are now represented as the "Joint Stakeholders." The Joint Stakeholders are refiling our original proposal regarding possible modifications to the Commission's energy concurrent with the March 10th and 11th stakeholder meeting and workshop. While Commission Staff's third revision of its proposed energy rules filed February 18, 2020, no longer eliminates requirements for renewable energy, Staff's proposal still has no requirement for energy efficiency, nor does it contain a clean energy standard, but only a "clean peak" requirement.

The REST and EEES rules, both individually and collectively, have provided substantial benefits to the state and utility ratepayers in the form of cost savings; reduced water use; tens of thousands of in-state, family-wage jobs; economic development; and

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[1] Joint Stakeholders original redlined energy rules proposal, https://docket.images.azcc.gov/E000002141.pdf

environmental benefits. These rules have been instrumental in ensuring that the most cost-effective resources are procured by utilities. As these rules have been effective and are functional, we recommend extending and improving upon them as the best method to provide continued benefits to ratepayers and the electricity system — rather than eliminating them and starting from scratch.

In response, the Joint Stakeholders have developed this comprehensive proposal modifying the Commission's existing rules and adding a clean energy focused standard. These comments serve as a summary and introduction to the Joint Stakeholder Rules and are accompanied by specific language for each modification in both clean and redline format. The intention of the Joint Stakeholder Rules is to provide a comprehensive alternative to the April 25th and July 2nd Staff Reports that addresses many of the proposals and ideas put forth by Commissioners, as well as the interests of the groups who have collaborated on this effort.

As described in detail below, the Joint Stakeholder Rules include enforceable standards for the following:

- 100% clean energy by 2045,
- 50% renewable energy by 2030,
- 10% distributed generation by 2030, and
- 35% cumulative energy efficiency savings by 2030.

The Joint Stakeholder Rules also move Arizona toward a more comprehensive IRP process that provides for more effective stakeholder engagement and ensures greater accountability, while preserving the RPP rules as separate from the others.

Finally, the Joint Stakeholder Rules recognize the importance of supporting a just transition for communities impacted by power plant closure by encouraging clean energy investment on Tribal Lands.

Collectively, the Joint Stakeholder Rules are designed to ensure that:

- There is continued progress and accountability toward clean energy investment by Arizona's regulated utilities.
- Arizona's regulated utilities pursue near-term actions focused on investing in clean energy resources that are local and cost-effective.
- Investment in new resources is targeted toward those resources that are less likely to introduce future stranded costs.
- Arizona prioritizes clean energy investment that creates in-state jobs, supports communities impacted by power plant closure, capitalizes on Arizona's superior solar resource, and that improves local air quality and public health.

The Joint Stakeholders are appreciative of the leadership demonstrated by the Commission in addressing these complex and important issues. This proposal addresses many aspects of the proposals put forth by Chairman Bob Burns, Commissioner Sandra Kennedy, Commissioner Boyd Dunn, and former Commissioner Andy Tobin.

II. Clean Energy Standard

The Joint Stakeholder Rules contain a new standard of 100% clean energy by 2045. This requirement puts Arizona on the path towards a zero-carbon energy system and is consistent with policies being developed across the Western United States. A standard of 100% clean energy by 2045 is achievable and necessary to address the impacts of climate change. The current energy rules do not contain a clean energy standard and, as such, the Joint Stakeholder Rules create a new policy for measurement and compliance.

Under the Joint Stakeholder Rules, Clean Energy Standard compliance would be measured using a mass-based regulatory structure that would maximize flexibility in meeting the Standard by focusing on carbon content rather than any specific technology. A baseline carbon emissions rate would be set based on an average of 2016-2018 levels and decreased progressively until the requirement of 100% clean by 2045 is achieved. By including a Clean Energy Standard in addition to an update to the REST and EEES, the Joint Stakeholder Rules provide value and flexibility to achieve Arizona's energy future.

III. Renewable Energy Standard

Arizona's current REST of 15% by 2025 was adopted in 2006 — over a decade ago. Arizona's leadership in renewable energy policy spurred incredible entrepreneurship and technological innovation. At that time renewables were a relatively nascent technology and investments made in renewables have brought us to the place we are today. Renewable energy from solar and wind are some of the lowest cost energy resources available. With continued policy leadership, battery storage will improve the ability for renewable energy to match load, enabling higher penetration at lower costs, boosting the state's economy, improving Arizona's air quality, and reducing water consumption from power generation.

As a result, the Joint Stakeholder Rules include an enforceable standard for 50% renewable energy by 2030. Together with the Clean Energy Standard, this proposal would make Arizona competitive with nearly every other state in the West.[2] The Joint Stakeholder Rules also contain updates to the existing REST that increase the required renewable energy percentages beginning in 2020 until 50% renewable energy by 2030 is achieved.

IV. Distributed Energy Requirement

The current REST includes a requirement for distributed generation ("DG") in section R14-2-1805. This requirement is often called the "DG carve-out." The current DG carve-out requires that 30% of the existing 15% REST be satisfied by obtaining Renewable Energy Credits ("RECs") from distributed energy resources. In 2025 this requirement amounts to 4.5% of retail sales. Half of this carve-out is required to come from residential applications and the other half is required to come from non-residential, non-utility applications. When this provision was originally enacted, Arizona offered upfront

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[2] The following standards have been adopted: Nevada: 50% renewable by 2030 and 100% clean by 2050; New Mexico: 50% renewable by 2030, 80% renewable by 2040, and 100% zero-carbon by 2045; Oregon: 50% renewable by 2040; Washington: 100% clean by 2045; California: 100% clean energy by 2045.

incentive payments to customers installing DG. In exchange for the incentive payment, DG customers provided the RECs associated with their DG system production to the utility for use in complying with the REST and the DG carve-out. Since incentives have expired, participation in DG has continued to grow in Arizona, but the utilities are no longer receiving RECs for new DG. No alternative method for REC transfer has developed resulting in the need to request waivers from this provision of the current REST.

As Arizona updates the REST, the DG carve-out should be updated in order to accommodate the current situation in which the RECs associated with DG are not provided to the utility, and to ensure that customers are provided the opportunity to participate in clean energy development in Arizona. To accomplish these goals, the Joint Stakeholders propose an updated Distributed Renewable Energy Requirement ("DRER"). The DRER will not be a carve-out of the updated REST, but rather a parallel program under which 10% of total retail sales will be required to come from distributed generation by 2030.[3] The requirement will begin at 4% in 2020 and will increase by six tenths of one percent each year until 2030 when the 10% requirement is reached. In this updated filing the Joint Stakeholders have removed the requirement that DG resources have a nameplate capacity of 50 kW or less and have re-instituted the requirement under the original DRER that half of the annual DRER be met with residential DG and half with non-residential DG. Compliance with the DRER will be measured based on DG production captured by the dedicated production meters installed by the utility at the customer's premise.[4]

The proposed DRER is reasonable and conservative. The initial target of 4% in 2020 is less than current penetration levels for Arizona Public Service Company (APS), Tucson Electric Power (TEP), and UNS Electric.[5] Prior to the end of net metering, APS projected

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[3] For purposes of the DRER retail sales will be measured inclusive of the solar production that is produced and consumed behind the meter.

[4] Production from Distributed Renewable Energy Resources will not be eligible for compliance under the REST unless RECs associated with the production are obtained and retired.

[5] See APS docket No. E-1345A-18-0226, TEP docket No. E-01933A-18-0238, and UNSE docket No. E-04204A-18-0239.

DG penetration as high as 18% in 2030[6]—a value significantly higher than the proposed requirement of 10% in 2030. As Arizona has moved away from retail rate net metering to an export credit rate, growth in DG is expected to slow significantly. Adoption of the DRER will ensure that there remains a viable path for customer participation in Arizona's clean energy future.

As utilities plan to meet the DRER, they should promote the development of customer-sited battery storage in combination with and in addition to DG. Such goals can be achieved through rate design and incentives, including compensation mechanisms for the utilization of Distributed Renewable Energy Resources to provide services in support of power system stability and power quality including "bring your own device" tariffs that compensate service aggregators for the coordination, operation, and dispatch of multiple customer-sited battery storage and DG systems.

V. Energy Efficiency Requirement

Since 2010 the current EEES has saved Arizona ratepayers money, energy, capacity, and water; stimulated the local economy; and reduced air pollutants — all cost-effectively. Benefits have included:

- More than $1 billion in net economic benefits for all Arizona ratepayers;
- More than 14 billion gallons of water saved; and,
- Energy savings equivalent to the consumption of more than 500,000 Arizona homes.[7]

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[6] Arizona Public Service Company. 2017 Integrated Resource Plan filed in Compliance with R14-2-703. April 2017. Table F-2, page 211.
[7] See 2010-2018 Annual Demand Side Management reports of Tucson Electric Power, Arizona Public Service Company, and UNS Electric filed with the Arizona Corporation Commission.

Energy efficiency is also Arizona's cheapest energy resource[8] and employs more than 40,000 people across the state.[9]

In order to reap the benefits of continued energy efficiency investment, the Joint Stakeholder Rules include an enforceable standard for 35% cumulative energy savings by 2030. The Joint Stakeholder Rules also contain updates to the existing EEES to reduce regulatory barriers to energy efficiency program deployment and comprehensiveness.

VI. Integrated Resource Planning Process Improvements

The Joint Stakeholders propose significant modifications to the RPP rules to address concerns about the current IRP process, including proposed changes that will increase the opportunity for stakeholder involvement, increase accountability, and improve transparency in utility planning.

As the Commission is aware, the prior IRPs submitted by APS and TEP were heavily focused on the procurement of gas resources to the detriment of other resources including renewable energy, energy storage, energy efficiency, and demand response. The Commission ultimately did not acknowledge the utilities' IRPs, which resulted in a gap in resource planning and highlighted the need for process improvements.

The Joint Stakeholders have undertaken considerable effort to propose rules that are best suited to Arizona and that are based on lessons learned from and best practices for resource planning from around the country. In addition to outlining a more user-friendly process that will enhance reporting requirements, improve and facilitate meaningful stakeholder involvement, and enable critical transparency for stakeholders and the Commission into a utility's development of its IRP, the Joint Stakeholder Rules outline a process that details specific actions to be taken in the case that an IRP is determined to be

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[8] According to Tucson Electric Power's 2017 Integrated Resource Plan, other resources cost substantially more including gas (at least 4-times more) and nuclear (at least 6-times more).
[9] Environmental Entrepreneurs, Energy Efficiency Jobs in America: Arizona: https://www.e2.org/wp-content/uploads/2018/09/ARIZONA-Dist.pdf

deficient. Under the proposed process, utilities must help the Commission and stakeholders understand why an IRP represents the best deal for ratepayers and how the IRP analysis and action plan has changed since the last Commission IRP review. Finally, utilities must return to the Commission for guidance or an amendment when major changes impact an IRP or IRP action plan.

VII. Transition for Impacted Communities

The Commission has recently taken steps to acknowledge the responsibility of utilities to provide support for communities impacted by the retirement of conventional power plants. Indeed, the pending Recommended Opinion and Order in Docket Nos. E-01345A-16-0036 and E-01345A-16-0123 directs Arizona Public Service Company to develop an initial transition plan for communities that will be impacted by the closure of the Four Corners Power Plant.

In addition to establishing a just transition plan and fund, the Commission can also support just transition efforts by encouraging clean energy development that directly benefits impacted communities. For example, there is strong potential for solar and wind development on Navajo and Hopi Lands that, if developed, could help Arizona achieve clean energy outcomes while also helping these communities transition to new economic bases.

To that end, the Joint Stakeholder rules include provisions that direct utilities to consider and give a preference to clean energy development opportunities in communities impacted by conventional power plant closures, including on Tribal Lands.

VIII. Conclusions

The Joint Stakeholders appreciate this opportunity to comment on this important conversation and to provide our proposed rules for the Commission's consideration. We are interested in engaging further on these issues and would welcome the opportunity to present the Joint Stakeholder Rules to the Commission at an upcoming meeting or workshop.

Demand Side Management:

Energy Efficiency & Demand Response

Demand Side Management: Energy Efficiency & Demand Response

Key Definitions

Demand side management (or DSM) refers to the wide and diverse array of energy efficiency and demand response technologies, services, programs, and strategies to help consumers optimize and reduce the energy use of their equipment, buildings, operations, and behavior. DSM investments help homeowners and businesses control their energy use, lower their utility costs, save water, and reduce toxic air pollution. DSM programs might support more efficient lighting, air conditioning, water heating, building insulation, behavior change, processing and manufacturing improvements, building energy codes, and appliance standards — to name a few examples.

Energy efficiency (EE), or the elimination of energy waste, means using less energy to perform the same task while providing the same or a better level of product, service, or amenity. For instance, installing insulation in a home improves both its efficiency and its comfort; and improving the efficiency of a manufacturing process enhances the competitiveness of a firm's operations.

Demand response (DR) is the practice of modifying (shifting or reducing) electricity usage during a particular period of time in order to better match electricity grid needs with available supply. Examples include direct load control programs which enable a utility company to increase the temperature setting of a smart thermostat or modulate the air conditioner of a participating ratepayer during periods of peak demand in exchange for a financial incentive.

DSM Offerings Available to Arizona Ratepayers

Arizona's utilities offer a comprehensive suite of EE and DR programs that are designed to touch all customer segments in the residential, commercial, and industrial sectors.[1] In the residential sector, programs are specially tailored for limited-income customers, renters, homeowners, and consumers who are renovating and building new homes — to name a few. In the commercial and industrial sector, programs are specially designed for businesses and industrial customers of all sizes - mom and pop, small, large, and mid-sized. Programs are also designed to serve the public sector including schools, nonprofits, and municipalities. Examples of some of the programs available to Arizona Public Service (APS) residential customers include:

- The Home Energy Checkup program, which brings a specially trained and certified contractor to the home to diagnose and solve a residence's energy problems.
- The Duct Repair and Sealing program, which sets a consumer up with a certified contractor to repair holes in the ductwork of HVAC systems.
- The Weatherization program, which provides qualified limited-income customers with energy-efficient home improvements to help them save money on their electricity bills.

Many of Arizona's EE programs have received national and regional recognition and have been upheld as models for other states and utilities to replicate.[2]

For more information on the energy efficiency programs offered by Arizona's electric utilities, visit: www.savewithsrp.com, www.aps.com/save, and www.tep.com/rebates.

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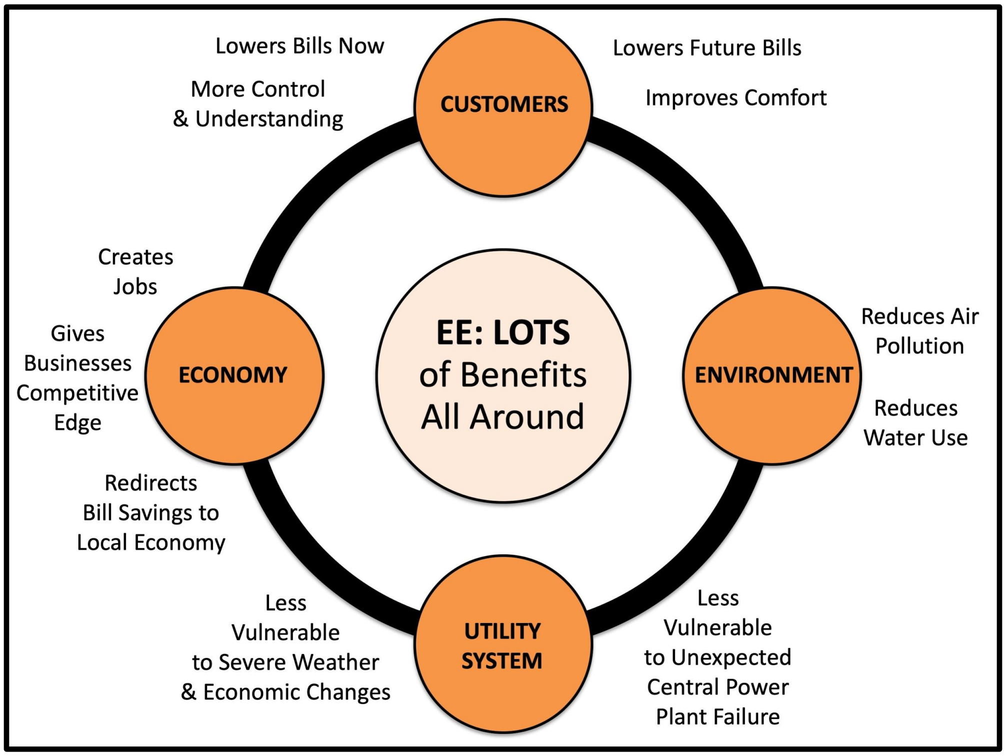
[1] In contrast, few utility investments are designed to serve all ratepayers. For example, a new power plant is primarily built to serve new customers versus existing ones. Similarly, a substation investment does not benefit all utility system customers even though all utility customers pay for that investment.

[2] Examples of programs that have received national recognition include APS' Multi-family Energy Efficiency program, APS' Home Performance with ENERGY STAR® program, APS' Solutions for Business program, and UNS Energy's Home Energy Assessment Program.

The Many Benefits of DSM

- EE saves all ratepayers money. It controls costs in two important ways. First, the least expensive energy is the energy we don't have to generate. According to Tucson Electric Power (TEP)'s most recent resource plan, other resources cost ~2-to-11 times more.[3] Because EE is the least expensive option, all customers benefit from its investment because they would otherwise pay for more expensive options to meet system needs. Second, reducing energy waste saves ratepayers' money in the long run because it means ratepayers don't have to pay for the construction of new power plants and distribution and transmission lines which EE investments avoid.



- EE is a boon for the economy: It helps businesses gain a competitive edge (thanks to newfound savings) and creates good paying jobs that are not easily outsourced. In addition, when residents save on energy bills, they redirect their savings to the local economy – strengthening the local restaurants, stores, and businesses. It also helps the environment by reducing air pollution and water consumption and helps to make our centralized power system less vulnerable to unexpected events like severe weather, including dust storms and heatwaves.
- EE is an extremely flexible resource that provides more flexibility in system planning and operations. It can be temporally targeted to provide savings in key hours of system stress. In this way it can reduce the need for additional resources by reshaping the net load curve and flattening ramps. Indeed, many EE measures have a high-level of peak-orientation. Examples include more efficient commercial lighting and controls, and residential and commercial air conditioning. EE programs can also be geographically targeted to certain customers and localities to provide savings in key locations of system stress.

Key DSM Statistics

- EE is Arizona's least-cost energy and capacity resource. In fact, TEP's 2020 Integrated Resource Plan shows that all other resources cost ~2-to-11 times more.[4]
- Unlike other energy resources, EE investments are meticulously and consistently tracked to ensure they are delivered as promised. They are stopped when they are not. No other investment has such scrupulous tracking and reporting requirements.

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[3] *See*: 2020 IRP Tucson Electric Power, Resource Cost Comparison Page 23: https://docket.images.azcc.gov/E000007291.pdf

[4] Ibid at 3.

- From 2010-2019, every $1.00 of ratepayer money invested in APS and TEP EE programs returned ~$3.92 in total benefits to ratepayers.[5]
- From 2010-2019, the EE programs of TEP, APS, and UNS Electric delivered more than $1.4 billion in net economic benefits to all Arizonans.[6]
- EE investments have helped create more than 40,000 jobs across the state, including more than 28,000 jobs in Phoenix and 6,000 jobs in Tucson.[7] These jobs pay well, are local, and are in hands-on fields like installation so they cannot be easily outsourced.
- Together, APS and TEP's EE programs have saved more than 15,000,000 gallons of water.[8]

Significant Policies & Opportunities Under Consideration in Arizona

(1) **Review & Approval of APS's 2020 DSM Plan -** Commissioners voted to approve APS's 2020 DSM Plan at their September 2020 Open Meeting. APS will invest ~$52 million in DSM programs and offer many new technologies to customers including connected water heaters and pool pumps. See Docket No. E-01345A-19-0088.

(2) **Review & Approval of Future DSM Plans for TEP** - In July 2019, Commissioners voted unanimously to approve TEP's DSM Plan through the end of 2020. Under the Plan, TEP will invest $22 million per year and provide numerous offerings including for air conditioner tune-ups, duct sealing, and energy efficient heating and cooling systems. See Dockets No. E-01933A-17-0250 and E-01933A-19-0071. TEP is developing its next DSM Plan now, which will come before the Commission at some point in the near future.

(3) **Extension and Expansion of the Commission's Electric EE Standard -** In 2010 the bipartisan Commission unanimously approved an Electric EE Standard[9] requiring regulated electric investor-owned utilities to achieve 22% cumulative energy savings by 2020.[10] If the EE Standard is not renewed by the end of this year, it will effectively sunset, and investment in Arizona's least cost-resource will likely decline (at least according to the recently filed resource plan of APS). Hundreds of Arizona's residential customer, small businesses, and large corporations[11] have filed comments calling on the ACC to extend and expand the EE Standard to 35% energy savings by 2030.[12]

(4) **Implementation of Salt River Project's (SRP) 2035 Sustainability Goals -** In 2019 SRP adopted 17 sustainability goals,[13] including new goals to invest in EE and DR through 2035. SRP is now developing its roadmap to deliver on these goals; and these plans will be reviewed by its Board at some point in the near future.

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[5] 2010-2019 Annual Demand Side Management reports of TEP, UNSE, and APS filed with the Arizona Corporation Commission.

[6] Ibid at 5.

[7] Environmental Entrepreneurs, Energy Efficiency Jobs in America: Arizona: https://www.e2.org/wp-content/uploads/2018/09/ARIZONA-Dist.pdf

[8] Ibid at 5.

[9] See Decision No. 71819, https://docket.images.azcc.gov/0000116125.pdf

[10] Energy savings of 20% of retail energy sales by 2020, plus 2% for reductions from demand response.

[11] See comments in Energy Rules docket, https://edocket.azcc.gov/Docket/DocketDetailSearch?docketId=21658#docket-detail-container1

[12] See a Joint Stakeholder proposal for updates Arizona's Energy Rules, signed by 32 organizations, https://docket.images.azcc.gov/E000005275.pdf

[13] See SRP 2035, https://www.srpnet.com/environment/sustainability/2035-goals.aspx

ENERGY EFFICIENCY BENEFITS ALL ARIZONANS

Commission leadership in 2010 established energy saving policies that continue to pay huge dividends. From 2010 - 2019 efficiency investments:

Created Jobs

Supported and enabled the growth of 40,000+ jobs statewide

Saved Energy

Provided savings equivalent to the energy use of more than 500,000 homes per year

Provided A ROI

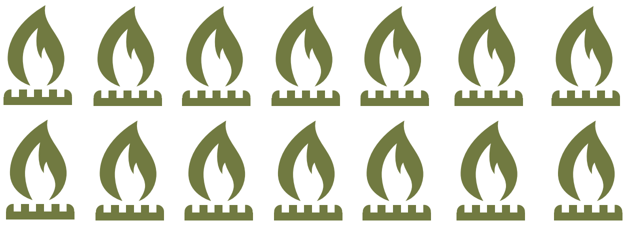
Every $1 of ratepayer money invested returned ~$3.92 in total benefits

Saved Water

Saved more than 15 billion gallons of water

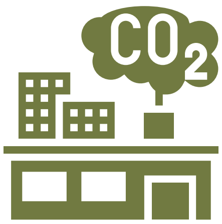
Avoided Capacity

Avoided the need to construct 14 combustion turbine units at Ocotillo



Cleaned Our Air

Reduced over 17 million metric tons of CO_2



SWEEP

SOUTHWEST ENERGY EFFICIENCY PROJECT

For more information, contact Caryn Potter at cpotter@swenergy.org

Sources: 2010-2019 Annual Demand Side Management Reports filed by Arizona Public Service and Tucson Electric Power with the Commission

Arizona Electric Utility Energy Efficiency Programs: A Success Story

December 2019

History

- Electric utility energy efficiency programs in Arizona ramped up starting in 2005 as a result of energy efficiency provisions in utility rate case settlement agreements.
- The Arizona Corporation Commission (ACC) unanimously 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 implemented during 2011-2020. Up to 2% of the total savings can be attained through credits from demand response programs.
- The ACC has adopted a policy statement to address utility financial disincentives to promoting energy savings. The policy allows regulated utilities to propose full revenue decoupling, which has been approved for the state's largest natural gas utility (Southwest Gas Co.), or other mechanisms. APS and TEP have proposed and received approval of lost revenue recovery and performance-based shareholder incentive mechanisms.
- The state's second-largest electric utility, Salt River Project (SRP), is a public power provider not regulated by the ACC. SRP established its own policy to meet 20% of its customers' energy requirements through energy efficiency and renewable energy by 2020. The policy also includes annual energy savings goals for the utility's energy efficiency programs.

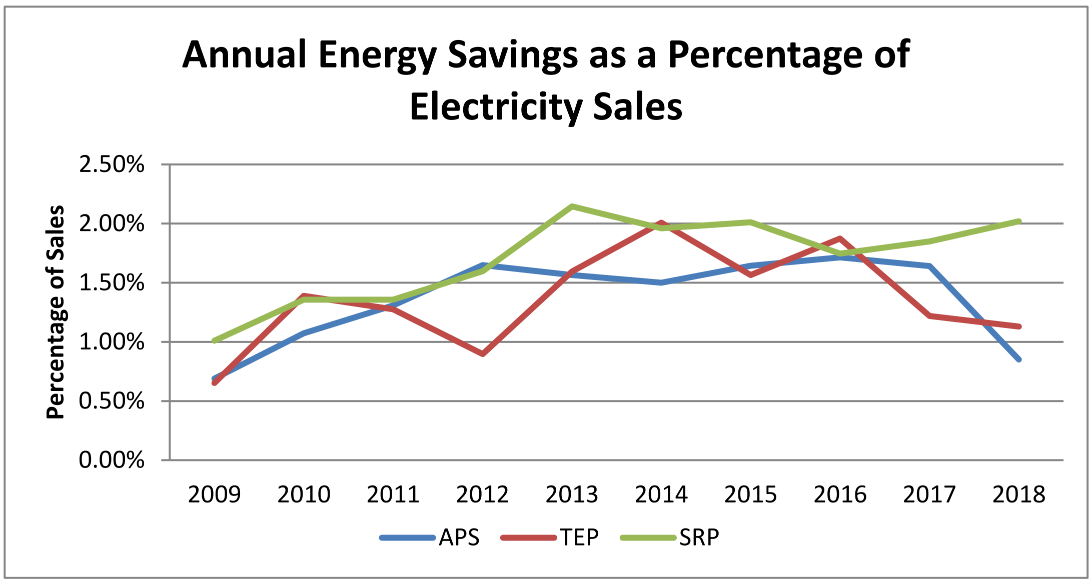
Utility Energy Efficiency Programs

- The state's largest electric utility, APS, serves about 1.25 million customers. Through 2017, APS implemented a comprehensive portfolio of energy efficiency programs, including traditional rebates for all types of efficiency measures, encouraging behavior change, funding for energy efficiency upgrades in schools, and support for codes and standards. However, APS scaled back its energy efficiency programs and shifted funding towards demand response programs in 2018.
- TEP serves about 425,000 customers in the Tucson area. It also has been implementing a comprehensive set of residential and commercial/industrial programs, including behavior change programs. As of 2018, TEP was slightly below the interim goal included in the state's EERS requirements.
- SRP serves about one million customers in and around Phoenix. It implements a wide range of energy efficiency incentive programs for its residential and business customers as well as a large-scale prepaid metering and energy education program. SRP also supports building energy code adoption and compliance.

Impacts of Energy Efficiency Programs

- As shown in the figure and table below, APS, TEP and SRP significantly expanded their energy efficiency programs and increased energy savings during 2009-16. However, annual energy savings declined for APS and TEP in 2017-18. Combined, these three utilities helped their customers realize electricity savings of approximately 8.0 billion kWh in 2018 from programs implemented during 2009-18. The savings are equal to more than 12% of total electricity use by customers of these three utilities in 2018.

- According to the utilities' own estimates, the projected net economic benefits from efficiency programs operated by the three utilities during 2009-18 totals $3.7 billion. This is equivalent to the electricity bills paid by the 2.4 million residential customers of the three utilities for nearly one year.
- The energy efficiency programs implemented during 2009-18 resulted in water savings of around 2.6 billion gallons in 2018 from the reduced operation of thermal power plants, enough water to supply about 19,000 typical Arizona households.
- As a result of a decade of energy efficiency programs, the three utilities cut their CO_2 emissions in 2018 by around 5.6 million metric tons. This is equivalent to taking approximately 1.15 million passenger vehicles off the road.
- Even with the drop in energy savings for APS and TEP in 2018, **Arizona was still the second-best state in the Western region (after California) with respect to utility energy savings achievement** according to the American Council for an Energy-Efficient Economy**.**



DSM Program Results of Arizona's Largest Electric Utilities, 2009-18

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
Spending ($ M)	51	83	103	113	119	116	125	123	114	86	1,033
Electricity Savings (GWh/year)	520	781	851	976	1,182	1,138	1,163	1,137	1,099	913	8,010
Savings as a % of Retail Sales	0.82	1.24	1.32	1.52	1.81	1.77	1.79	1.75	1.69	1.40	NA
Peak Reduction (MW)	94	130	188	220	257	278	290	319	289	316	NA
Net Economic Benefits ($ M)	130	290	290	428	422	453	401	419	409	485	3,727
CO_2 Emissions Reductions (thousand metric tons/yr)	364	547	596	683	827	797	814	796	769	639	5,607

Notes: Total energy savings is not equal to the sum of the savings achieved each year to avoid double-counting the savings provided by SRP's pre-paid metering program. Also, savings are at the customer level and do not include avoided T&D losses. CO_2 emissions reductions assume avoiding generation from coal-fired and gas-fired power plants in equal amounts.

Source: Utility data are taken from annual Demand-Side Management reports submitted by APS and TEP to the ACC along with annual reports issued by the Salt River Project.

For more information, contact Ellen Zuckerman, ezuckerman@swenergy.org.

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>
ROBERT "BOB" BURNS, Chairman
BOYD DUNN, Commissioner
SANDRA D. KENNEDY, Commissioner
JUSTIN OLSON, Commissioner
LEA MARQUEZ PETERSON, Commissioner

IN THE MATTER OF COMMISSION INQUIRY INTO UTILITY PREPAREDNESS PLANS TO ENSURE SAFE AND RELIABLE OPERATIONS DURING COVID-19	Docket No. AU-00000A-20-0050
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S APPLICATION FOR APPROVAL OF COVID-19 EMERGENCY RELIEF PACKAGE FOR APS CUSTOMERS EXPERIENCING FINANCIAL HARDSHIP DUE TO COVID-19 PANDEMIC	Docket No. E-01345A-20-0080

Joint Comments in Response to Arizona Public Service (APS) COVID-19 Emergency and Temporary Customer Relief Package

On behalf of the Arizona PIRG Education Fund, the Building Performance Association, and the Southwest Energy Efficiency Project, we would like to offer our joint comments relating to Arizona Public Service's (APS) proposal for an emergency and temporary customer relief package relating to the COVID-19 pandemic.[1] While it's imperative to act quickly to provide assistance to customers impacted by the pandemic, we respectfully request that you require APS to provide additional information, such as by responding to the questions we raise in this letter, before you vote on this item on May 5. In addition, we ask the Commission to also move quickly to approve the APS 2020 DSM Plan to provide customers with additional opportunities

[1]APS proposal for a COVID-19 Emergency Relief Package for customers, https://docket.images.azcc.gov/E000005986.pdf

ACC - Docket Control - Received 4/24/2020 11:31 AM
ACC - Docket Control - Docketed 4/24/2020 11:45 AM

to reduce their bills through energy efficiency.

Background

The COVID-19 pandemic is a public health and economic crisis unlike any we have ever seen. Unfortunately, the extent of this crisis is still not fully understood and we do not know how bad it will become or how long it will last. However, we do know that since March 15, Arizona has processed 417,962 claims for unemployment, which represents 8.7% of the total workforce of Arizona that is eligible for the unemployment insurance program.[2] We also know that municipalities across Arizona are facing budget shortfalls due to declines in tax revenues.[3] The effects of COVID-19 are intensifying the already lived experiences of poor health, hunger, isolation and the threat of homelessness for those most vulnerable in our society and other Arizonans are also experiencing the impact. Now more than ever, it is important that the Commission adopt permanent solutions to assist ratepayers with economic recovery.

Currently, APS has $39 million[4] in ratepayer money that has been collected through the Demand Side Management Adjustor Clause (DSMAC) but remains unspent. APS proposes to fund its COVID-19 relief package with $16 million from this pot of money. To understand the current over-collection of DSM funds through the DSMAC, it is helpful to review some recent history of the DSMAC.

1) In 2017, the Commission approved a DSM budget of $66.6 million[5] of which approximately $47 million is collected through the DSMAC and an additional $20 million is collected through base rates[6] as part of the 2017 APS Rate Case Settlement Agreement, Decision No. 76295. **No new budget or DSM plan has not been approved since 2017.**
2) In 2017, APS achieved 1.64% energy savings as a percent of retail sales with an annual spend of $65 million[7] out of the $66.6 million.[8]
3) In 2018, APS achieved 0.85% energy savings as a percent of retail sales with an annual spend of $31.0 million out of the $66.6 million originally approved in 2017.

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[2] "Unemployment numbers in Arizona showed steep rise due to COVID-19 crisis,"https://www.azfamily.com/news/continuing_coverage/coronavirus_coverage/unemployment-numbers-in-arizona-showed-steep-rise-due-to-covid-19-crisis/article_facdcd9a-7a95-11ea-a4b0-7bcd3017f9ed.html

[3] 'We really need to be prepared for the worst': How metro Phoenix cities are responding to coronavirus, https://www.azcentral.com/story/news/local/arizona/2020/03/24/arizona-cities-expect-coronavirus-hit-budgets-delay-big-projects/2880308001/

[4] Page 9 of APS's COVID-19 Emergency Relief Package, https://docket.images.azcc.gov/E000005986.pdf

[5] APS has not had a DSM plan approved since 2017. The ACC approved budget reflects that amount. https://docket.images.azcc.gov/0000182248.pdf

[6] The ACC increased the portion of DSM funding in base rate collections from $10 million to $20 million in Decision No. 76295, Exhibit A, Section VIII, Appendix D as a result of 2017 APS Rate Case Settlement Agreement, https://docket.images.azcc.gov/0000182160.pdf

[7] APS 2017 Annual DSM report, https://docket.images.azcc.gov/0000186159.pdf

[8] https://docket.images.azcc.gov/0000182248.pdf

4) In 2019, APS achieved 0.6%[9] energy savings as a percent of retail sales with an annual spend of $33 million[10] out of the $66.6 million originally approved in 2017.
5) On December 30th, 2019, APS submitted its 2020 DSM Plan,[11] which proposed a $50 million budget that would utilize $20 million in base rates combined with the nearly $32 million already collected from the DSMAC, resetting the DSMAC to zero moving forward.

As shown above, APS has significantly cut back on investments in energy efficiency in recent years. At the same time, the Commission has not acted on an APS DSM Plan since 2017. Together these two actions have led to a significant underspending of approved funding for DSM programs.

Questions on the APS Proposed Emergency Customer Relief Package

While we recognize the importance of acting swiftly to provide immediate relief to ratepayers, the APS filing is incomplete in a number of ways. First, the Company does not present any analysis of other potential sources of funding it considered before proposing to utilize the DSMAC to fund COVID-19 relief. Second, the APS relief package proposal is missing important details about how the Company plans to market, track, and evaluate the availability of funds and determine customer eligibility. **We ask the Commission to require APS to provide answers to the following questions by COB April 28.** The answers to these questions will provide the Commission, as well as Staff, stakeholders, and concerned ratepayers with important information so that you can make an informed decision on this important matter.

1. What other options were explored to provide financial relief to customers?
2. Was the option of using a portion of DSM funds to leverage zero percent or low-interest energy efficiency financing considered for all ratepayers who may need to make HVAC purchases during this time of uncertainty?
3. In what categories is APS experiencing net cost savings (e.g. fuel, operating) as a result of COVID-19? Per category, what are the estimated net cost savings through August 2020?
4. Does APS anticipate revenue shortfalls as result of COVID-19 and if so, for what net amount per category through August 2020?
5. Does APS anticipate coming back to the Commission with a request to provide additional funds for COVID-19 relief? If so, what will determine the need for additional funds and what do you anticipate will be the source of those funds?
6. How does APS plan to track any expenditures made with relief funds?
7. How does APS plan to evaluate the use of relief funds?
8. How does APS plan to let ratepayers know about the availability of relief funds?
9. How does APS plan to determine which ratepayers are eligible to receive financial assistance?

[9] Please note that SWEEP provided this number as a preliminary estimate as SWEEP didn't have sales data when this was calculated, so SWEEP used 2018 sales as a proxy.
[10] APS 2019 Annual DSM Report, https://docket.images.azcc.gov/E000005121.pdf
[11] APS 2020 DSM Plan proposal, https://docket.images.azcc.gov/E000004276.pdf

10. Will APS commit to providing a monthly update on relief support to this docket?

The Role of Energy Efficiency in Economic Recovery

Energy efficiency has a vital role to play when it comes to the economic recovery of Arizona after the worst of the COVID-19 pandemic has passed.The unspent DSM funds that have been collected from customers can not only assist in reducing the compounding effects of poverty, but also stimulating economic recovery during times of recession and uncertainty by supporting existing jobs,[12] creating new ones, and boosting jobs in labor-intensive sectors that are key for Arizona's economy,[13] such as construction and home renovation. More than 44,000 locally-sourced jobs in Arizona are in the energy efficiency industry.[14] 23,000 of those jobs are in Heating, Ventilation, Air Conditioning (HVAC) services alone.[15] 59% of these jobs come from small businesses that employ 1 to 5 employees.[16] However, as a result of the COVID-19 pandemic 1,050 Arizonans working in clean energy lost their jobs in March 2020, with significantly larger impacts still expected. [17]

Governor Ducey recognized the critical role of energy efficiency in his March 23rd Executive Order detailing Building, Construction, and HVAC as essential services.[18]

In addition to supporting tens of thousands of jobs, energy efficiency can also provide lasting and permanent bill savings to customers by reducing energy usage through upgrades to buildings and appliances. These savings will persist long after the COVID-19 crisis is behind us, helping customers emerge from this time in a stronger financial position. Expanding energy efficiency programs and helping Arizona's households lower their utility bills is especially important at a time when more people are staying home and/or working from home, and incomes are reduced as a result of the COVID-19 pandemic.

Given the benefits of energy efficiency programs, we believe now is the time to further employ energy efficiency programs to provide benefits to a greater number of customers.

Emergency COVID-19 Customer Relief Package Recommendations

DSM has consistently provided financial relief to ratepayers, and the relief is a long-lasting solution, not a temporary fix. Now is the time to increase, not decrease, investments in energy efficiency programs for ratepayers. Therefore we request the Commission explore other sources of funding before utilizing DSM funds that could be better spent on energy efficiency programs that reduce customer bills. In addition, we make the

[12] https://www.iea.org/articles/energy-efficiency-and-economic-stimulus

[13] Year-over-year, the construction industry added 14,800 jobs, or about 10.2%, which is tops in the nation based on percentage increase. According to non-seasonally adjusted data, 161,300 work in the construction industry in Arizona as of June 2018. https://roc.az.gov/newsarticle/arizona-leads-nation-nevada-not-far-behind-adding-construction-jobs

[14] "Arizona: Energy Efficiency Jobs in America, https://e2.org/wp-content/uploads/2020/04/E2-Clean-Jobs-America-2020.pdf

[15] Ibid.

[16] Ibid.

[17] https://e2.org/wp-content/uploads/2020/04/Clean-Energy-Jobs-Initial-COVID-19-Memo-Final.pdf

[18] https://azgovernor.gov/governor/news/2020/03/list-essential-services

following recommendations on the COVID-19 relief package for the Commission's consideration.

1) The $1 million allocated to the "*Reserve Fund for General Service Supports*" should be either removed from the budget or used immediately for customer relief.

2) The Company currently has no budget set aside for marketing the "*Small Business Hold Program*." We are concerned that this program is only available as-requested by the customer, yet there are no additional dollars set aside for education and outreach. We suggest to either include funds for a proper rollout of the program or not offer this part of the program at all.

3) The Company's alternative proposal to return $36 million in collected but unspent DSMAC funds to all APS customers should be rejected. The funds originally collected from the DSMAC were to be spent on DSM programs that would help customers to lower their bills, improve the buildings in which they work and live, as well as reduce energy waste. These funds are even more important for ratepayers now.

4) APS should be required to file a revised and strengthened 2020 DSM Plan within 30 days of a decision regarding the COVID-19 relief package, or before the subsequent Open Meeting (whichever comes first) to address the impacts of COVID-19 and ensure that any changes to the DSMAC required as a result of this proceeding are reflected in the Plan.

5) We request that the Commission vote on the revised APS 2020 DSM Plan at the June 2020 Open Meeting. It is our sincere hope that the input APS receives from advocates through the DSM Collaborative is incorporated into its revised plan.

Amended 2020 DSM Plan Recommendations

Now more than ever, energy efficiency can help customers who are struggling to pay their electric bills. With social distancing being the proper response to the COVID-19 pandemic, there is a unique opportunity to expand energy efficiency offerings that help customers and support the local economy. **That is why we urge the Commission to prioritize approval of APS's proposed 2020 DSM Plan, after APS makes revisions as suggested below.**

The currently proposed APS 2020 DSM Plan restores a number of programs, including weatherization for low-income households and opportunities for multi-family residences.

To provide added relief to customers, including those not previously struggling, there are opportunities to offer enhanced programs that respond to how energy efficiency projects can be deployed during this pandemic. We ask the Commission to request that APS add the following in their revised plan:

1. New delivery models that can be used in this time of social distancing, such as remote energy assessments, virtual inspections of installed measures, increased emphasis on do-it-yourself (DIY) retrofits, and use of on-line stores and incentives for energy efficiency measures. These program strategies can provide ratepayers with options to save money and keep employees in the energy efficiency industry working at a time when in-home services are restricted or not advised for certain segments of the population such as the elderly or those with other health risks.

2. Enhanced rebates for all customers and a specific focus on those impacted economically by the COVID-19 crisis. For example, APS could offer larger incentives for high efficiency HVAC units purchases by low-income families or households that have seen their income significantly reduced as a result of the pandemic.

3. Explore opportunities to leverage attractive financing options for increased energy efficiency.

COVID-19 relief is especially critical as many APS ratepayers will soon be faced with triple-digit temperatures and air conditioning units will once again start running. In addition to the above, we support APS conducting broad and targeted communication to ratepayers about its energy efficiency programs and ways to save money. This is especially critical for residential customers struggling to pay their bills now and can help to put them on a stronger financial footing in the future.

Furthermore, we support special considerations for non-residential customer relief, particularly in a manner that can impact ratepayers as taxpayers and stimulate local economies.

1. Increased incentives for energy efficiency projects implemented by State and local governments - By investing in energy efficiency now, state and local governments can soon see financial savings on monthly electric bills and help offset decreased tax revenue. The savings will continue long after the pandemic is over.

2. Increased incentives for energy efficiency projects implemented by Schools - By investing in energy efficiency now, schools can soon see financial savings on monthly electric bills now and continue saving well into the future at a time when funding for school districts is likely to be diminished.

3. Small Businesses - Many small businesses do not have the financing to employ energy efficiency on their own. Enhanced programs that meet their needs will help small businesses recover much more quickly, while contributing to the local economy.

Finally, to expedite the review process, the Commission should defer a detailed analysis of cost-effectiveness until the filing of the 2020 Annual Report. Analyzing cost-effectiveness based on real program implementation data and not projected numbers is best-practice in the majority jurisdictions across the Southwest and the country.

We appreciate the opportunity to work with the Commission and with APS to ensure that ratepayers receive temporary and emergency assistance in these challenging times, as well as the opportunity to realize the long-term benefits that energy efficiency offers.

We respectfully submit these comments on Friday, April 24th, 2020

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Time-Sensitive Valuation of Electricity Savings in the Southwest

By Adam Bickford and Howard Geller
July 2017

SWEEP
SOUTHWEST ENERGY
EFFICIENCY PROJECT

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Acronyms and Abbreviations

APS	Arizona Public Service Company
CC	Combined Cycle Generator
CT	Combustion Turbine Generator
DSM	Demand Side Management
ERP	Electric Resource Plan
IRP	Integrated Resource Plan
MTRC	Modified TRC Test
NPC	Nevada Power Company
PCT	Participant Cost Test
PNM	Public Service Company of New Mexico
PSCo	Public Service Company of Colorado
RIM	Ratepayer Impact Test
RMPU	Rocky Mountain Power – Utah
SCC	Social Cost of Carbon
SCT	Societal Cost Test
SPPC	Sierra Pacific Power Company
SRP	Salt River Project
T&D	Transmission and Distribution
TEP	Tucson Electric Power
TRC	Total Resource Cost Test
UCT	Utility Cost Test

Executive Summary

In evaluating the cost effectiveness of utility energy efficiency and other demand-side management (DSM) programs, utilities compare the avoided costs of alternative resources to the cost of adopting energy efficiency and load management measures. Utilities in the Southwest use a variety of inputs and methods to calculate avoided costs. This paper focuses on the avoided costs that six major investor-owned electric utilities and one large publicly-owned utility in the Southwest use in their analysis of the cost-effectiveness of energy efficiency programs.

The paper reviews how the utilities in the Southwest determine avoided generation capacity and generation capacity costs, avoided energy costs, transmission and distribution investment deferrals, and any value for avoided pollutant emissions.

The paper then examines the actual value of energy savings for specific programs and end-uses based on data provided in utility DSM program annual reports and program evaluation studies. We present the total net present value of all avoided costs per unit of lifetime energy savings by program type. In considering the value of energy savings across different types of programs and measures, the paper highlights the time-varying value of energy savings.

This analysis shows that residential cooling programs tend to yield a higher value per unit of energy savings than do other types of programs, for each utility. Likewise, residential lighting programs tend to yield a lower value per unit of energy saving than do other types of programs. These results are logical given that residential cooling programs result in greater peak demand reduction per unit of energy savings, while residential lighting programs result in relatively little peak demand reduction, and energy savings on peak are more valuable than energy savings off peak. All of the utilities in the Southwest are summer peaking utilities.

The paper concludes with a set of recommendations for the valuation of energy savings in utility resource planning and DSM program cost-effectiveness analysis. The recommendations include: 1) value all of the benefits (i.e., avoided costs) produced by energy efficiency programs and measures, and do so accounting for time-varying avoided costs; 2) at most use the after-tax weighted-average cost of capital to determine the net present value of avoided costs, and consider using a lower discount rate than the after-tax WACC given the different nature of utility supply-side investments and energy efficiency programs; 3) establish avoided generation capacity costs based on time-varying marginal generation resources identified in the preferred plan of an IRP, rather than using a generic resource, such as a generic combustion turbine; 4) include avoided transmission system costs in the valuation of energy savings, and possibly avoided distribution system costs as well; and 5) monetize and value avoided CO2 emissions and possibly other pollutant emissions.

Introduction

Hourly avoided costs are one of the primary inputs to calculating the time-dependent value of energy efficiency. Utilities in the Southwest use a variety of inputs and methods to calculate avoided costs. This paper focuses on what components of avoided costs investor-owned utilities in the Southwest include in their energy efficiency benefit-cost analyses. In addition to the components each utility includes in its avoided cost, this paper also assesses whether these utilities use time-dependent avoided cost values.

This paper focuses on the avoided cost approach used by the seven largest electric utilities in the region where SWEEP works. These include both investor-owned utilities and one public-power utility:

- Arizona Public Service Company (APS)
- Salt River Project (SRP)
- Tucson Electric Power (TEP)
- Public Service Company of Colorado (PSCo)
- NV Energy, dba Nevada Power Company and Sierra Pacific Power Company (NPC and SPPC)
- Public Service Company of New Mexico (PNM)
- Rocky Mountain Power – Utah (RMPU)

With the exception of RMPU, all of the utilities conduct planning for service territories in a single state. RMPU is part of PacifiCorp, a multi-state utility operating in five states.[1] Because of its size and degree of integration, PacifiCorp conducts its planning at the multi-state system level.

The discussion below summarizes how the selected Southwest utilities value the energy savings from their DSM programs by considering four dimensions:

- The utility cost-effectiveness tests and the utility discount rate used by each utility;
- A description of the steps each utility uses to develop its avoided costs and to account for externalities such as avoided pollutant emissions;
- The methodology utilities employ to value energy savings, including their time-dependent value, in the face of planning constraints and regulatory requirements;
- A comparison of the value of energy savings across different types of energy efficiency programs and end-uses.

The sources of the analysis include recent integrated resource plans, energy efficiency program plans, energy efficiency annual reports, and DSM program evaluation reports filed by each utility. These documents are supplemented by interviews with key utility personnel.

Lawrence Berkeley National Laboratory (Berkeley Lab) recently published a study on the time-varying value of energy efficiency, evaluating five energy efficiency measures in four regions of the country.[2] Among the findings in that study is that avoided transmission and distribution costs create some of the

[1] PacifiCorp, 2017: 136
[2] Mims, Eckman and Goldman, 2017.

largest capacity benefits of the time-varying value of efficiency measures in the regions studied. This paper focuses on what components of avoided costs utilities in the Southwest include in their energy efficiency program analyses, as well as the actual value of energy savings for different types of programs in the region.

Utility Cost-Effectiveness Tests and the Discount Rate

Utility Cost-Effectiveness Tests

The National Action Plan for Energy Efficiency (2008) identifies five common cost-effectiveness tests that are used for evaluation of energy efficiency and other DSM programs: The Participant Cost Test (PCT), the Ratepayer Impact Test (RIM), the Societal Cost Test (SCT), the Total Resource Cost Test (TRC), and the Utility Cost Test (UCT). An additional test, used by PSCo and RMPU, the Modified TRC Test (MTRC), is the standard TRC plus an additional value ("adder") to account for non-energy benefits. These tests consider different components of measure, program, or portfolio, benefits and costs embodying different perspectives on economic effectiveness.

Cost-effectiveness tests are applied and reported at multiple levels: for the entire DSM portfolio, at the individual DSM program level, and, in some cases, at the level of individual efficiency measures. For example, for the Nevada utilities, individual programs and the portfolio must pass the TRC test. In contrast, in Colorado, groups of programs implemented at the sectoral level – Residential or Business – must pass the modified TRC test, but individual programs (termed "products" by PSCo) do not have to pass.

The utilities regularly calculate and publish the results of multiple benefit-cost tests, even when a state regulatory commission defines one test as its "primary" test. Table 1 describes the cost effectiveness test(s) used by each of the utilities discussed in this paper.

Table 1 - Cost-Effectiveness Tests used by Southwest Utilities

State	Utility	Tests Evaluated	Level	Primary Test
Arizona	Arizona Public Service	All five main tests.	Measure, Program and Portfolio	Societal Cost Test (SCT)
Arizona	Salt River Project	Total Resource Cost Test (TRC) and Ratepayer Impact Test (RIM)	Program and Portfolio	Total Resource Cost Test (TRC)
Arizona	Tucson Electric Power	Societal Cost Test (SCT)	Measure, Program and Portfolio	Societal Cost Test (SCT)
Colorado	Public Service Company of Colorado	Modified Total Resource Cost Test (MTRC)	Program, Sector and Portfolio	Modified Total Resource Cost Test (MTRC)
Nevada	Nevada Power Company and Sierra Pacific Power Company	Total Resource Cost Test (TRC)	Program and Portfolio	Total Resource Cost Test (TRC)
New Mexico	Public Service Company of New Mexico	Utility Cost Test (UCT)	Program	Utility Cost Test (UCT)
Utah	Rocky Mountain Power, Utah	All five main tests, plus the Modified Total Resource Cost Test (MTRC)	Program and Portfolio	Utility Cost Test (UCT)

Source: ACEEE, 2017

Discount Rate Used in Benefit-Cost Analyses

The utilities consistently use their approved weighted-average cost of capital (WACC) as the nominal discount rate in calculating the net present value of energy savings in their various benefit-cost analyses. Arizona utilities regulated by the Arizona Corporation Commission use their approved WACC as the discount rate, rather than a societal discount rate, for valuing energy savings under the Societal Cost Test.[3] As shown in Table 2, the majority of utilities examined in this paper employ an after-tax value of their WACC as the discount rate used in valuing energy efficiency.

[3] The ACC has opened a docket examining a number of issues related to DSM program benefit-cost analysis including what is the appropriate discount rate for use in the SCT. See ACC, 2017.

Table 2 - Nominal Discount Rates Used in Valuing Energy Efficiency

State	Utility	Nominal Discount Rate (%)	Pre-Tax or After-Tax
Arizona	APS	7.50	After-Tax
	SRP	7.12	After-Tax
	TEP	7.04	After-Tax
Colorado	PSCo	6.78	After-Tax
Nevada	NPC	8.09	After-Tax
	SPPC	7.62	After-Tax
New Mexico	PNM	10.77	Pre-Tax
Utah	RMPU	6.66	After-Tax

Sources

APS	ACC, 2017.
TEP	ACC, 2017.
SRP	Dreiling and Morey, 2017.
PSCO	PSCo, 2016a: Volume 2: 181.
NPC	NPC, 2015: Volume 7: 36.
SPPC	SPPC, 2015: 21.
PNM	NMPRC, 2016: 55-69.
RMPU	PacifiCorp, 2015: Volume 1: 141.

Calculating Utility Avoided Costs and the Derivation of Load Shapes

The components of utility avoided costs combine values from: 1) avoided generation costs (including reserves), 2) avoided costs of transmission and distribution investments, 3) avoided O&M costs, 4) avoided fuel costs, and 5) in some cases, valuation of avoided pollutant emissions. The methods Southwest utilities use to assess each component are described in this section.

Avoided Capacity and Energy Costs

Utilities in the Southwest value energy savings from DSM programs by analyzing the avoided costs as electricity consumption is reduced. The sources of avoided capacity and energy costs vary by hour, and are generally one of three types:

1. The hourly avoided cost for a fixed generation resource, such as a gas combustion turbine (CT) or a combined cycle (CC) plant;
2. The hourly cost of the marginal generation resource, typically taken as the output from the utility's production cost model or distribution cost model; or
3. A combination of these methods, i.e., treating the output of a production cost model or a load forecasting model as if it were a fixed resource.

In every case, avoided costs are calculated by the utility on an hourly basis, but are reported on an annual or monthly basis. For a given utility, the avoided cost for generation capacity is developed as part of a specific resource plan, and avoided energy costs are developed through a production cost model using a resource plan as an input.

The Arizona investor-owned utilities, APS and TEP, derive their avoided capacity costs from their preferred resource plan. In these plans, the marginal deferrable resource identified is a combustion turbine or similar resource, although other resource types could be selected. The avoided capacity cost value is established for the resource based on the peak-hour cost plus the reserve-margin cost for the forecast peak summer day. These values are used as an input to the utility's production cost model, which determines the hourly value of an avoided MWh. [4]

PNM bases its avoided capacity costs on the results of the production cost model used in their IRP analyses. The cost of the selected marginal resource forms the basis for the avoided cost of capacity. The economic benefit of DSM is the product of the reductions in capacity and energy and the avoided cost of generation. [5]

Both PSCo and the Nevada utilities employ a hybrid model. PSCo has created a generic avoided cost resource it calls the "Resource Acquisition Period (RAP) CT".[6] The avoided cost values are established using the Strategist Model, but with an assumption that the avoided generating resource (i.e., a generation plant not constructed) would be a company-owned combustion turbine.[7]

The Nevada utilities derive avoided generation costs from their load forecast and dispatch model. These costs are based on the generation costs during a 16-hour peak period in the summer months. Once developed, the avoided cost profile is applied across the entire year as a series of monthly costs per MWh saved.[8] SRP takes a similar approach; avoided generation costs are derived using a 6-hour peak period over the summer months.

PacifiCorp calculates a levelized cost of electricity savings for similar groups, or "bundles," of DSM measures. These bundles and their associated costs are entered into their system optimization model and compete directly with supply-side resources on an hourly basis. The levelized costs of resources that are selected provide the basis of the avoided costs.[9]

Avoided Transmission and Distribution Costs

The assumptions regarding avoided transmission investments and their valuation vary widely among the seven utilities. Some utilities include values for avoided transmission and distribution costs; some include terms for avoided transmission in their planning assumptions but set the underlying value of these terms at $0/kW-year. For example, both the Nevada utilities and PacifiCorp include a "transmission and distribution deferral credit" in their calculation of DSM costs.

[4] Lindemann, 2017 and Wontor, 2017.
[5] O'Connell, 2017.
[6] PSCo, 2017a: 107-109
[7] CPUC, 2014: 31-33
[8] Vukanovic, 2017.
[9] PacifiCorp, 2017: 113-139 and Morris, et. al. 2017.

APS, TEP and SRP include a value for avoided transmission costs in their avoided costs, but do not disclose this value.

In New Mexico, PNM does not assume any value for avoided transmission and distribution costs in its valuation of the benefits from utility energy efficiency and DSM programs.[10]

In Colorado, PSCo includes avoided T&D capacity investments in its calculation of avoided costs. This value is based on a system planning method to determine deferred T&D projects resulting from forecast DSM achievements. This value was previously set at zero, but a new study was performed that estimated avoided T&D costs of approximately $11-16/kW-yr. during 2017-37.[11] This new value is being used starting in 2017.

The Nevada utilities include a significant avoided transmission cost based on the approved marginal cost study filed in each utility's General Rate Case. The value is currently $52.15/kW-year. The Nevada utilities do not include a value for avoided distribution system investments in their valuation of energy savings.[12]

RMPU applies a transmission and distribution deferral credit in its calculation of the avoided costs from energy efficiency and other DSM programs. The deferral credit is currently $13.56/kW-year. This value is derived from PacifiCorp's system-wide resource planning.[13]

Although RMPU uses its transmission and distribution deferral credit to account for avoided distribution system investments, assessing an accurate value for these deferrals is complicated by several factors.[14] Not only do local distribution nodes that can benefit from deferrals have to be identified (i.e., at the substation level), strategies for geo-targeting DSM programs to address potential overloads also have to be developed.[15] Because of these challenges, none of the utilities explicitly value distribution system investment deferrals independently from transmission deferrals.

Avoided O&M and Fuel Costs

Avoided O&M and fuel costs are typically embedded in the cost of the avoided generation resource that is used to calculate a utility's avoided cost. The range of costs that are included in a generation resource includes variable fuel costs, fixed and variable O&M costs, and capital costs for emissions reduction equipment.

APS, TEP, and PNM use the hourly marginal generator cost from their production cost model; in doing so, the avoided fuel and O&M costs are embedded in, and vary by, the selected resource. This method applies to both existing and planned resources. In its 2017 IRP, TEP commissioned a "Flexible

[10] Lindemann, 2017.
[11] PSCO, 2016b: 342.
[12] Vukanovic, 2017.
[13] PacifiCorp, 2017: 57-74.
[14] Morris, et. al., 2017.
[15] Neme and Grevatt, 2015.

Generation Technology Assessment" report, which provided engineering estimates of O&M and fuel costs of eight classes of supply-side and renewable resources.[16]

PSCo runs its resource planning model both with and without DSM programs included in order to determine avoided O&M and energy costs. In this manner, the model provides estimated annual avoided energy and O&M costs.[17] While the values are reported on an annual basis, they are derived from hourly analysis by the planning model.

The Nevada utilities use existing and projected O&M costs and fuel costs as inputs to its production model, PROMOD. The outputs of this model form the basis of the avoided resource used in the Nevada utilities' cost-effectiveness modeling.[18]

RPMU and PacifiCorp calculate a "Stochastic Mean NPVRR" value from its simulation studies. These studies produce a NVPRR risk value that accounts for fixed and variable O&M costs and for variable fuel costs over a range of planning scenarios. The result of this analysis is used to create a "Stochastic risk reduction credit" that is applied to the levelized cost of DSM resources.[19] The process that PacifiCorp uses to account for the levelized costs of new DSM measures, and to develop avoided costs for classes of resources, is discussed in the next section.

Derivation of Load Shapes

Due to the variations in the value of avoided cost both seasonally and hourly, the load shapes of energy savings are important for the valuation of different energy efficiency measures and programs. The derivation of load shapes for energy efficiency measures varies considerably among utilities. Each utility uses different sources and employs adjustments based on the impact of past experience with classes of measures and their regulatory requirements. While some utilities use publically available load shapes data (e.g., from the California DEER database) as the basis for their avoided cost calculations, these public load shape data are modified to reflect local weather conditions and specific evaluation results. The modified load shapes are generally treated as proprietary information, and are not publically available.

APS develops hourly avoided costs using a production cost model, and multiplies them by the hourly load shapes of DSM measures. Hourly load shapes are developed internally through territory-specific field work and annual M&V studies. Once developed, these load shapes, along with the portfolio-level savings targets specified by the Arizona EERS, are modelled using an internal spreadsheet model as APS develops its annual DSM plan.[20]

TEP uses measure-specific load shapes to calculate annual savings values, which are then aggregated into programs. Annual energy savings are determined by third-party evaluations, and then are

[16] TEP, 2017: 307-346.
[17] PSCo, 2016b:342.
[18] NPC, 2016: 227-228.
[19] PacifiCorp, 2017: 166-168.
[20] Wontor, 2017.

apportioned to hourly load shapes to determine hourly impact of system load. These load shapes were originally developed in 2011 using values from the California Database for Energy Efficient Resources (DEER), the California Commercial End-Use Study (CEUS) and the Building America - National Residential Efficiency Measures Database. The load shapes were later modified to reflect the representative climate of the Tucson area.[21] TEP uses results from periodic program evaluations to update the load shapes used for specific measures.

SRP utilizes Cadmus' PortfolioPro model to evaluate the cost-effectiveness of measures and programs within the portfolio. The model is also used to determine program-related load reduction. PortfolioPro contains a set of sector, building, and end-use load shapes, which are used to derive the capacity reductions. The load shapes utilized were developed by SRP's third-party evaluator and calibrated to the Arizona desert climate.[22]

PNM relies on hourly impact shapes for classes of measures derived from the customized load shapes provided by the Strategist model, PNM's IRP planning model. The accuracy of these load shapes is verified through program impact evaluations that are carried out at least once every three years.[23]

The load shapes PSCo employs are adapted from measure-specific load shapes developed in Minnesota in the 1990s. These shapes were modified to match the Colorado climate and used to establish avoided cost values for four day-types across all 12 months in a year. These day-types correspond to a weekend day, the monthly peak-day, the non-peak weekday, and low-weekday load-shape.[24]

The Nevada utilities also use the PortfolioPro model to screen measures and determine the cost effectiveness of the measures and programs included in their DSM portfolios. The PortfolioPro model contains a set of measure load shapes calibrated to the utility service territories (Las Vegas for the Nevada Power Company and Reno for the Sierra Pacific Power Company).[25]

RMPU, through its parent company, PacifiCorp, has the most complex approach to modeling load shapes and avoided costs. As mentioned above, PacifiCorp operates in multiples states and models its avoided costs at the system level. To facilitate the construction of a manageable number of hourly supply curves, energy efficiency measures are grouped into "bundles" according to the measure's cost per MWh saved. These bundles, which range from measures costing less than $10.00/MWh saved to over $1,000/MWh saved, are converted to hourly load shapes that are differentiated by state, sector, market segment, and end use. These energy efficiency measure bundles, which represent a levelized cost of saved energy, net of the transmission and distribution credits and the Stochastic risk-reduction credit discussed above, are then inputted into the system planning model and compete against supply-side resources to develop the least-cost portfolio.

[21] TEP, 2017b: 112-114 and Lindemann, 2017.
[22] Dreiling and Morey, 2017.
[23] O'Connell, 2017.
[24] Petersen and Walsh, 2017.
[25] Vukanovic, 2017.

This process, which incorporates the hourly variations of similar bundles of energy efficiency measures, is used to develop PacifiCorp's avoided costs.[26] The methodology for developing these avoided costs is documented in PacifCorp's "Class 2 DSM Decrement Study"[27], which is published after the release of each IRP. This study creates nominal avoided costs, in $/MWh, for eight classes of energy efficiency measures (e.g., Residential Cooling, Residential Lighting, etc.) calibrated to meet the characteristics of its two regions, the West region (Oregon, Washington and California) and the East region (Idaho, Utah and Wyoming). When RMPU evaluates measure-based savings, or considers adding new measures to a program, it uses these nominal avoided costs in its planning. In some cases, these values are used in program evaluations with additional factors (e.g., a proxy value for non-energy benefits in the calculation of a modified TRC test).[28]

Accounting for Externalities: Valuing Avoided Pollutant Emissions

With respect to reduced emissions of the criteria pollutants (SOx, NOx, and PM10) and CO2, most of the utilities report emissions reductions associated with DSM savings, but few monetize emission reductions or include them in their avoided costs. The exception to this is PNM, which includes a value for avoided CO2 emissions on a per kWh basis beginning in 2022. The value starts at $0.0111/kWh in 2022 and increases to $0.0345/kWh by 2033.[29] As noted above, the Colorado PUC has approved non-energy benefits adders to the economic benefits of energy efficiency and other DSM programs. The non-energy benefits adders are intended to include some valuation of avoided pollutant emissions, but are not explicitly tied to specific avoided emissions. In addition, RMPU includes a proxy value for avoided pollutant emissions and other non-energy benefits in one of the benefit-cost tests that it runs.

Utility-specific Data and Results

In this section, we first present summary tables of key assumptions for utility avoided capacity, avoided energy, and avoided transmission costs for the seven utilities. These values reflect publically available information taken from the respective utilities IRPs and energy efficiency/DSM program annual reports. We then provide program-specific values for the total benefits per unit of lifetime energy savings for different program types and utilities. These values were derived from utility reports documenting annual program performance. The total benefits are primarily, and in some cases, entirely, the utility's avoided costs. For a few of the utilities, the benefits include valuation of avoided CO2 emissions or non-energy benefits more generally. The benefits are those calculated by the utility using the primary cost effectiveness test in each jurisdiction.

[26] PacifiCorp, 2017: 113-139.
[27] PacifiCorp, 2015c.
[28] See Cadmus, 2017: 99.
[29] PNM, 2016: 20.

Table 3 - Values of Components of Avoided Costs

	Arizona		
	APS	**SRP**	**TEP**
Component	**2017**	**2016**	**2017**
Avoided Cost of Generation Capacity	Based on deferrable generation in IRP.	Avoided generation cost is the marginal cost calculated from production cost studies. Natural gas CT is used as the basis to determine the avoided cost.	Based on results of the hourly generation dispatch model.
Avoided Marginal Energy Costs	Values not publically disclosed.	Values not publically disclosed.	Values not publically disclosed.
Avoided Transmission Costs	Avoided cost for transmission embedded in overall avoided generation cost.	Avoided cost for transmission investments embedded in overall avoided generation cost.	Avoided cost for transmission investments embedded in overall avoided generation cost.
Avoided Distribution Costs	No avoided cost of distribution.	Avoided cost for distribution embedded in overall avoided generation cost.	No avoided cost of distribution.
Avoided Pollutant Costs	Avoided pollutants reported, but not monetized.	Not Provided.	Avoided pollutants reported, but not monetized.
	Colorado	**Nevada**	
	PSCo	**NPC**	**SPPC**
Component	**2016**	**2014 and 2016**	**2014 and 2016**
Avoided Cost of Generation Capacity	Resource Acquisition Period (RAP) CT: a gas-fired CT. Costs start at $8.31/kW-month in 2016 and escalate to $12.93/kW-month in 2035.	The avoided cost of generation is the marginal cost calculated from production cost studies. A natural gas-fired combined cycle plant used to develop the avoided capacity cost.	The avoided cost of generation is the marginal cost calculated from production cost studies. The type of resource used to develop the avoided cost of capacity is a natural gas-fired combined cycle plant.
Avoided Marginal Energy Costs	Simple Average Hourly Energy costs start at $32.98/MWh in 2016 and escalate to $66.19/MWh in 2035.	Monthly Capped Long-Term Energy Costs range between $17.88/MWh in April 2017 and $160.20/MWh in July 2046.	Monthly Capped Long-Term Energy Costs range between $18.15/MWh in April 2017 and $150.90/MWh in July 2044.
Avoided Transmission Costs	$0.00/kW-year (1)	$52.15/kW-year	$51.56/kW-year
Avoided Distribution Costs	$0.00/kW-year (1)	$0.00/kW-year	$0.00/kW-year
Avoided Pollutant Costs	Value of avoided pollutants not estimated but included as part of the 10% adder for non-energy benefits (25% adder for low-income programs).	The cost of emissions is embedded in Production Cost Model.	The cost of emissions is embedded in Production Cost Model.

	New Mexico	Utah
	PNM	RMPU
Component	2015 and 2016	2015 and 2017
Avoided Cost of Generation Capacity	Defined as the marginal generation resource at the summer peak hour. Value comes from the dispatch model. $80.00/kW-year for 2018 to 2034.	Sources are derived from the marginal resource at the system level, not at the state level.
Avoided Marginal Energy Costs	Cost escalates from $27.10/MWh in 2018 to $53.90/MWh in 2034.	Avoided costs vary by measure category. For 2017, nominal avoided costs vary between $38.44/MWh for Plug Loads and $162.74/MWh for Residential Cooling.
Avoided Transmission Costs	$0.00/kW-year.	T&D deferral credit of $13.56/kW-year.
Avoided Distribution Costs	$0.00/kW-year.	T&D deferral credit of $13.56/kW-year.
Avoided Pollutant Costs	Avoided CO2 emissions value starts at $11.10/MWh in 2022 and escalates to $34.50/MWh in 2034.	Not Estimated.

(1) As noted above, PSCo started to value avoided T&D costs in its 2017/2018 DSM program plan.

Sources

APS	Energy savings data for Estimated Avoided Cost Calculation: APS, 2017a. Technical details about system costs: APS, 2017b.
TEP	Energy savings data for Estimated Avoided Cost Calculation: TEP, 2017a. Technical details about system costs: TEP, 2017b.
SRP	SRP, 2017.
PSCo	PSCo, 2017.
NPC	Sources of Long Term Avoided Costs: NPC, 2016. Energy efficiency savings values: NPC, 2015: Volume 7.
SPPC	Data on Long-Term Avoided Costs SPPC, 2016b: Volume 10, 128-132 Energy efficiency savings values: SPPC, 2015.
PNM	Avoided Cost Information: PNM, 2017a, p. 20.
RMPU	Transmission Deferral Value: PacifiCorp, 2017: Volume 1 p. 153. Avoided Energy Cost: PacifiCorp, 2015c.

Table 4 provides the total value of lifetime energy savings in $/kWh saved for a set of common energy efficiency programs and end-uses, for each utility. These programs include residential lighting, residential cooling, residential home retrofits, residential new construction, commercial lighting, commercial cooling, commercial building retrofits and commercial new construction. Where available, separate estimates are presented for small business lighting and small business cooling programs. We chose to report the value of energy savings over the lifetime of the various measures or programs, rather than considering only first year energy savings, since the benefits (i.e., avoided costs) accrue over the lifetime of the programs.

The values in Table 4 were derived from the most recent annual DSM program reports for each utility (either the 2015 or 2016 annual reports) and/or individual program evaluation reports. The value of lifetime energy savings is generated by dividing the net present value of program benefits (i.e., avoided costs and in some cases non-utility benefits) by the lifetime energy savings, yielding a $/kWh saved metric. These values reflect the net present value of avoided costs over the estimated lifetime of each program or set of energy efficiency measures, depending upon the conventions used by each utility.

Calculating the values in Table 4 is complicated by the way each utility designs its programs and reports energy savings. In some cases, it was not possible to break out specific end uses. In other cases, a utility may combine different end-uses into a single program; for example, multiple commercial measures may be included under the rubric of a "Commercial Comprehensive" program. Frequently, a utility will

Table 4 - Estimates of Program-Specific Avoided costs per unit of Lifetime Energy Savings ($/kWh)

	Arizona			Colorado	Nevada		New Mexico	Utah
	APS	**SRP**	**TEP**	**PSCo**	**NPC**	**SPPC**	**PNM**	**RMPU**
Residential Programs/Applications								
Lighting	$0.0304	$0.0170	$0.0360	$0.0971	$0.0196	$0.0195	$0.0295	$0.0541
Cooling	$0.0488	$0.0590	$0.0765	$0.1579	$0.0565		$0.0158	$0.1631
Building Retrofit	$0.0496			$0.1946			$0.0419	$0.0536
New Construction	$0.0425	$0.0270	$0.1387	$0.1411				
Commercial Programs/Applications								
Lighting	$0.0284	$0.0130	$0.0573	$0.0432	$0.0163	$0.0200		$0.0512
Cooling			$0.0459	$0.0652	$0.0142	$0.0174		$0.0983
Building Retrofit							$0.0458	
New Construction	$0.0403	$0.0370	$0.0494	$0.0579			$0.0393	
Small Business Lighting	$0.0284	$0.0940	$0.0410	$0.0388				
Small Business Cooling			$0.0328					

Sources

APS	Energy savings data for Estimated Benefit Calculation: APS, 2017a. Technical details about system costs: APS, 2017b.
TEP	Energy savings data for Estimated Benefit Calculation: TEP, 2017a. Technical details about system costs: TEP, 2017b.
SRP	SRP, 2017.
PSCo	PSCo, 2017a and PSCo, 2017b.
NPC	NPC, 2016b: Tables DSM-4 and DSM-5, pp. 9-10.
SPPC	SPPC, 2015.
PNM	PNM, 2017b: Attachment SMB-2, Table 6-1, p 39.
RMPU	PacifiCorp, 2015c. 2017 Nominal Value.

present the first year energy savings for particular measures in a program but the net present value of lifetime benefits for the entire program. In that case, lifetime energy savings are calculated by multiplying the first-year savings by the reported effective useful life of a measure or program. Likewise, the benefits (i.e., avoided costs) are pro-rated by the proportion of the measure's first-year savings to the program level first-year savings. Beyond variation in reporting practices, the differences in valuation of benefits are due to the methodologies and assumptions each utility employs. Thus, these estimates are general indicators of the value of energy savings for specific programs and end-uses.

In considering these values, caution is necessary in comparing different utilities to one another. As explained above, different utilities estimate avoided costs differently and are more (or less) comprehensive in the types of avoided costs that are included. In addition, program performance varies in part due to differences in climatic conditions. Consider the value of energy savings for residential cooling programs. Residential cooling programs in the very hot Arizona climate generate energy savings most if not all of the year, while cooling programs in Colorado or Utah generate energy savings in the summer only. Thus, avoided costs per kWh saved, averaged over the year, may be higher in a place like Colorado compared to Arizona because more of the energy savings are during peak demand periods in Colorado.

Despite these limitations, the values in Table 4 suggest that residential cooling programs yield a greater value of energy savings than other types of programs, with a few exceptions. For example, a kWh saved by SRP's residential cooling program has 3.5 times the value of a kWh saved by the utility's residential lighting program. For RMPU, the same ratio is 3.0; for PSCo, it is 1.6; and for Nevada Power it is 2.9. These results are logical, given that cooling programs yield more "on peak" savings and thus have higher avoided capacity values than other types of programs.

All of the utility systems considered in this paper experience their peak demands during the mid-to-late afternoon hours during the summer months. Residential lighting savings mostly occur later in the evening, and thus do not provide as much peak demand reduction per kilowatt-hour saved. This does not mean that residential lighting efficiency programs are not cost effective or desirable; it simply points out that the energy savings from lighting efficiency measures tend to have less value than savings from other types of programs.

Commercial programs do not demonstrate the same relationship that residential programs do because of the differing load shapes for the same end use (e.g., lighting or cooling) between residential and commercial buildings. In commercial buildings, lighting and cooling are used for many more hours of the day than are typical in residential buildings. For some utilities, the value of a kWh saved is higher for the lighting program compared to the cooling program. This is because in commercial buildings, both lighting and cooling efficiency measures provide energy savings during peak demand periods.

Recommendations

The information in this paper highlights a number of practices that will improve the valuation of energy savings by utilities in the Southwest and elsewhere.[30]

Value All Avoided Costs and Take into Account the Time-Varying Value of Avoided Costs

It is important and appropriate to value all of the benefits (i.e., avoided costs) produced by energy efficiency programs and measures. For example, utilities should value avoided T&D capital costs as well as avoided generation costs, and value avoided CO2 and other pollutant emissions. Also, avoided cost valuation should be done considering the time-value of energy savings and demand reduction. A more comprehensive analysis of avoided costs could lead to more programs passing cost-effectiveness screening, as well as demonstrating for policy makers and other stakeholders the full benefits (value) of these resources.

Use an Appropriate Discount Rate

The selection of the discount rate is important to calculating the appropriate net present value of energy savings over the lifetime of energy efficiency measures. In calculating benefits, use of a lower discount is generally preferred, as it does not reduce benefits as rapidly over the lifetime of a measure. For all but one of the utilities discussed here, the after-tax weighted average cost of capital (WACC) from the utility's last rate case is used as the primary discount rate. PNM is the outlier in that it uses a before-tax WACC. The use of the after-tax WACC is more appropriate as the utility cost of capital, because it reflects that actual net cost of capital for a utility. A recently published national manual for energy efficiency program cost-effectiveness evaluation acknowledges that the after-tax WACC is the proper utility cost of capital.[31]

In performing the TRC or UCT tests, an argument can be made for using a discount rate that is less than the utility's after-tax WACC. This is because investments in energy efficiency programs and measures have a different risk profile than traditional utility capital investments. There is often little or no risk of a utility failing to recover the costs for its approved energy efficiency programs, as costs are often recovered through automatic utility bill surcharges rather than use of utility debt or equity. Likewise, energy efficiency programs consist of many discrete energy efficiency measures, and overall portfolio performance is well-established and relatively low risk. Therefore, utilities and their regulators should seriously consider using a lower discount rate than the WACC in valuing avoided costs from a TRC or UCT perspective.[32]

[30] These best practices represent the observations of SWEEP, and do not necessarily reflect the opinions of the utilities referenced in this report.
[31] National Efficiency Screening Project (NESP), 2017, p. 75.
[32] NESP, pp. 72-84.

In addition, it is appropriate and widely accepted that a social discount rate should be used for determining cost effectiveness using the Societal Cost test.[33] This discount rate, such as the 10-year U.S. Treasury bond rate, is generally very low, in part to reflect low risk and inter-generational equity.

Base Avoided Generation Capacity Costs on Results of an IRP

It is preferable to establish avoided generation-capacity costs based on time-varying marginal generation resources identified in the preferred plan of an IRP, rather than using a generic resource, such as a generic combustion turbine (CT). The hourly avoided costs from the projected marginal resource are likely to be more consistent with future resource development and operation, as compared to basing the avoided generation capacity cost on a generic resource. In addition, values from the marginal generator are more likely to be consistent with fuel and O&M costs assumed in the IRP, as well as reflect the changing generation mix for a utility.

A secondary recommendation is to make the results of both the IRP preferred plan and any production cost models available for examination by interested parties. Most of the utilities discussed in this paper did not disclose the values of avoided generation capacity. When values are published, they are often aggregated to a monthly or annual value. Utilities and stakeholders should discuss opportunities for sharing and reviewing information on the valuation of avoided generation, potentially with the completion of confidentiality agreements.

Include Valuation of Avoided Transmission and Distribution Investments

Transmission deferral values are included in the valuation of energy savings by the Nevada utilities, RMPU, and by PSCo starting in 2017. Berkeley Lab recently published a study on the time-varying value of energy efficiency, evaluating five energy efficiency measures in four regions of the country.[34] Among the findings in that study is that avoided transmission and distribution costs create some of the largest capacity benefits of the time-varying value of efficiency measures in the regions studied.

Utility energy efficiency programs can provide energy savings (as a fraction of total retail sales) of 1% to 3% per year.[35] Thus, energy efficiency programs can have a significant impact on load growth, and combined with other factors (such as the impacts of federal energy efficiency standards and adoption of distributed energy resources), can eliminate load growth entirely. This means that energy efficiency programs will have an impact on the need for transmission investments over the long run. Thus, utilities should include a value for avoided transmission investments in their valuation of the benefits of energy efficiency programs.

Valuing deferred distribution system investments is done in some jurisdictions and is gaining credence.[36] We recommend that utilities consider including valuation of avoided distribution system costs in the economic analyses of their DSM programs. In addition, we recommend that utilities investigate

[33] NESP, p. 83.
[34] Mims, Eckman and Goldman, 2017.
[35] Relf, Baatz and Nowak, 2017, p. 17.
[36] Neme and Grevatt, 2015.

opportunities for using energy efficiency in a more targeted manner, in order to defer distribution system upgrades in particular parts of the distribution network that are fully loaded or overloaded. If this is done, it would be logical to value avoided or deferred distribution system investments in the benefit-cost analysis of all geo-targeted energy efficiency programs at a minimum.

Monetize Emissions Reductions

Many utilities report emission reductions, including a reduction in CO2 emissions, from their energy efficiency and other DSM programs. However, in the Southwest, only PNM monetizes avoided CO2 emissions in the valuation of the benefits of energy efficiency programs. Emissions reductions have direct impacts on air quality and have indirect impacts on health and quality of life. We recommend that these benefits be monetized and included in the assessment of DSM program cost-effectiveness. The approach used by PSCo, which adds a fixed percentage to the utility system benefits in order to value non-energy benefits broadly (known as the non-energy benefits adder approach), is suboptimal in our view.[37] It does not provide an incentive for selecting programs or measures that could maximize emission-reduction benefits. Therefore, we recommend that utilities and policy makers directly value emissions reductions in energy efficiency and DSM programs benefit-cost analyses.

Conclusion

This paper examines the ways that seven utilities in the Southwest value the energy savings from their energy efficiency and other DSM programs. It reviews the approaches used by individual utilities including the approach to valuing avoided generation capacity and the steps taken to value transmission and distribution deferrals, avoided O&M and energy costs, and emissions reductions. It finds that there is considerable variation in the way that the utilities conduct this valuation, although all utilities employ methodologies that take into account time-varying values for at least some of the avoided costs.

The paper also presents the value of energy savings, in terms of the net present value of avoided costs per unit of lifetime energy savings, for various types of energy efficiency programs for each utility. This analysis shows that residential cooling programs tend to yield a higher value per unit of energy savings than do other types of programs, for each utility. Likewise, residential lighting programs tend to yield a lower value per unit of energy saving than do other types of programs. These results are logical given that residential cooling programs result in more peak-demand reduction per unit of energy savings than do residential lighting programs. All of the utilities in the Southwest are summer peaking utilities.

In addition, this review provides several recommendations for the valuation of energy savings including: 1) value all of the benefits (i.e., avoided costs) produced by energy efficiency programs and measures, and do so accounting for time-varying avoided costs; 2) use an appropriate discount rate—at most, the after-tax utility weighted cost of capital, and possibly a significantly lower discount rate; 3) base

[37] However, a decision by the Colorado PUC has directed PSCO to include the Social Cost of Carbon (SCC) as a sensitivity case in Phase II of its 2016 ERP. The SCC begins at $43.00 per ton in 2022 and increases to $69.00 per ton in 2050; see CPUC, 2017: 25-31. It is currently unclear whether this decision, which is applied to PSCO's base modelling assumptions, will be applied to its cost-effectiveness modeling for its DSM resources.

avoided-generation capacity costs on time-varying marginal generation resources identified in the preferred plan of an IRP, rather than using a generic resource; 4) include avoided transmission costs and potentially deferred or avoided distribution system investments; and 5) value avoided CO_2 and possibly other pollutant emissions.

The 2019 State Energy Efficiency Scorecard

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Contents

Executive Summary

Key Findings

This report ranks US states on their policy and program efforts to save energy.

- First place goes to **Massachusetts**, which leads the *State Scorecard* for the ninth year in a row. Thanks to a strong policy framework established under its Green Communities Act a decade ago, the state continues to achieve among the highest levels of utility savings in the nation. Earlier in the year, regulators approved a new three-year efficiency plan, including an expanded portfolio of programs intended to help align savings efforts with statewide greenhouse gas reduction goals. Massachusetts aims to reduce emissions by 80% by 2050.
- Rounding out the top 10 are **California** at #2 and **Rhode Island** and **Vermont**, tied at #3, followed by **New York, Connecticut, Maryland, Minnesota, Oregon,** and **Washington**.
- **Maryland** is this year's most-improved state. Utility efficiency programs, delivered through the EmPOWER Maryland initiative, have steadily evolved in recent years, spurred by robust legislative savings targets. Meanwhile the state continues to strengthen efficiency in the buildings and transportation sectors, establishing strong building energy codes, directing funding toward public transportation, and seeking to accelerate adoption of electric vehicles.
- Other states to watch include **New Jersey** and **New York**, where utilities and regulators continue to work to design strengthened efficiency programs to meet new utility savings targets approved in 2018. These states and others have established ambitious clean energy goals to transition to a carbon-free economy, while including energy efficiency as a key pillar in their strategies to do so.
- **Kentucky** fell the farthest in the rankings due to a 2018 decision that discontinued most of Kentucky Power's demand-side management programs. Other utilities in the state have seen similar reductions in program funding.
- Savings from ratepayer-funded electric efficiency programs remained fairly level compared with last year's results, totaling approximately **27.1 million megawatt-hours**. These savings are equivalent to about 0.73% of total retail electricity sales in the United States in 2018, enough to power more than 2.6 million homes for a year.
- States continue to update and strengthen residential and commercial building energy codes. Since the publication of the 2018 IECC, states like **Maryland**, **Massachusetts**, **Nebraska**, **Illinois**, and **Ohio** have adopted the newest code versions, and numerous other states are currently reviewing these codes for potential adoption in the near future.
- It was an especially big year for state appliance standards, with four states—**Washington, Colorado, Hawaii,** and **Nevada**—adopting new laws and an additional six states and the District of Columbia filing bills.

The *State Energy Efficiency Scorecard*, now in its 13th edition, ranks states on their policy and program efforts. It assesses performance, documents best practices, and recognizes leadership. The report captures the latest policy developments and state efforts to save energy and highlights opportunities and policy tools available to governors, state legislators, and regulators.

Figure ES1 shows the states' rankings, divided into five tiers for easy comparison. Later in this section, table ES2 provides details of each state's scores.

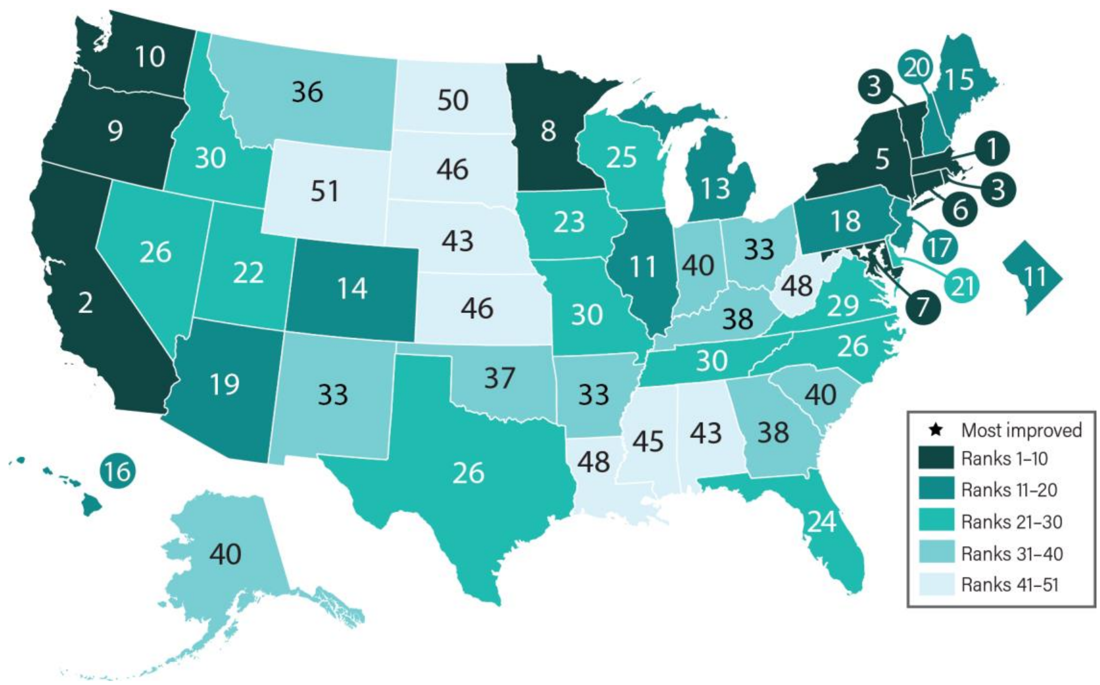

Figure ES1. *2019 State Scorecard* rankings

It was a whirlwind year for energy efficiency in 2019 at the state level. Many legislatures and governors established the transition to clean energy and reduced greenhouse gas (GHG) emissions as their top priority and increased their efficiency efforts to help achieve it. While leading states like Massachusetts, California, and New York continued to innovate and advance model programs, some of the most exciting stories emerged from states where efficiency has historically been overlooked as a resource. Nevada, New Mexico, Washington, New York, and Maine all adopted 100% clean energy goals coupled with plans to ramp up efficiency investment. In Virginia and New Jersey, utilities unveiled significant expansions of efficiency program portfolios in response to game-changing clean energy bills passed in 2018. State legislatures in Colorado, Washington, and Hawaii adopted new appliance standards in the biggest wave of state-level standard adoption in this decade. States also led the way in addressing challenges and opportunities surrounding building electrification and increasing uptake of electric vehicles as a means to achieve a low-carbon future.

POLICY AREAS

The *Scorecard* compares states across six policy areas:

- Utility and public benefits programs and policies
- Transportation policies
- Building energy efficiency policies
- Combined heat and power (CHP) policies
- State government–led initiatives around energy efficiency
- Appliance and equipment standards

Table ES1 provides examples of states that have adopted best-practice policies in each area. For more information about leading states, refer to the *Scorecard* chapter corresponding to each policy area.

Table ES1. States adopting best-practice policies

Area	States	Achievements
Utility and public benefits	Massachusetts, Rhode Island, Vermont	All have continued to post electric utility savings above 2% of retail sales, the highest levels in the nation.
Transportation	District of Columbia, California, Massachusetts, Oregon, Vermont	Each of these jurisdictions has adopted California's vehicle emissions standards as well as its Zero-Emission Vehicle (ZEV) programs, and each has adopted goals to reduce vehicle miles traveled and transportation-related GHGs.
Building energy efficiency	California, Illinois, Oregon, Pennsylvania, Texas, Maryland, Massachusetts, Nebraska, New York, Washington	These states have strengthened statewide building energy codes by adopting 2015 or 2018 IECC code versions, in addition to devoting resources to maintaining code compliance.
CHP	California, Maryland, Massachusetts, New Jersey, New York, Rhode Island	All these states have promoted CHP as an energy resource through establishment of interconnection standards, CHP production goals, and deployment incentives.
State government initiatives	California, Connecticut, Delaware, Massachusetts, Rhode Island, Vermont	These states led this year for offering loan and grant programs to spur energy savings, setting efficiency standards for public buildings and fleets, and investing proceeds from carbon pricing policies in efficiency programs.
Appliance/equipment standards	California, Colorado, Nevada, Washington, Hawaii	Each of these states passed appliance standards this year that are expected to save consumers hundreds of millions of dollars on utility bills.

SCORES

Table ES2 presents state scores in the six policy areas and their total scores.

Table ES2. State scores in the 2019 *State Scorecard*

Rank	State	Utility & public benefits programs & policies (20 pts.)	Trans-portation policies (10 pts.)	Building energy efficiency policies (8 pts.)	Combined heat & power (3 pts.)	State government initiatives (6 pts.)	Appliance efficiency standards (3 pts.)	**TOTAL SCORE (50 pts.)**	Change in rank from 2018	Change in score from 2018
1	Massachusetts	20	8.5	7	3	6	0	44.5	0	0.5
2	California	15.5	8.5	7.5	3	6	3	43.5	0	0
3	Rhode Island	20	6	5.5	3	6	0	40.5	0	–0.5
3	Vermont	18	6.5	6	2	6	2	40.5	1	0
5	New York	14	8.5	6.5	2.5	5.5	0	37	1	1.5
6	Connecticut	12.5	7.5	7	2.5	6	1	36.5	–1	–1.5
7	Maryland	12.5	7.5	6	3	5.5	0	34.5	3	4.5
8	Minnesota	14.5	5.5	6	1.5	5	0	32.5	0	0.5
9	Oregon	10.5	7.5	6.5	1.5	5	1	32	–2	–3
10	Washington	9	7	6.5	2	5	2	31.5	–1	0
11	District of Columbia	9.5	9	6	1	3.5	0	29	1	1.5
11	Illinois	11.5	5	6	2.5	4	0	29	1	1.5
13	Michigan	14	3.5	6	1	4	0	28.5	–2	0
14	Colorado	9.5	4.5	5.5	0.5	5	2	27	0	1.5
15	Maine	10.5	5.5	2.5	2.5	5	0	26	–1	0.5
16	Hawaii	11	4	5.5	1	2.5	1.5	25.5	0	2.5
17	New Jersey	6.5	6	6	3	2.5	0	24	1	2.5
18	Pennsylvania	4.5	5.5	7	2	4.5	0	23.5	0	2
19	Arizona	9.5	4	4	1.5	2.5	0	21.5	–2	–0.5
20	New Hampshire	9.5	3	3.5	0.5	4.5	0	21	1	1.5
21	Delaware	3	5	5	1.5	6	0	20.5	1	2
22	Utah	6.5	3	5.5	0.5	4	0	19.5	–2	–1.5
23	Iowa	9	2.5	5	0.5	1.5	0	18.5	1	1.5
24	Florida	2	4.5	6	0	4	0	16.5	–1	–1
25	Wisconsin	7.5	1	3.5	0.5	3.5	0	16	4	0.5
26	Nevada	4.5	2.5	4	0	4	0.5	15.5	3	0
26	North Carolina	3	3.5	4.5	1	3.5	0	15.5	0	–0.5
26	Texas	1	3	7	0.5	4	0	15.5	–1	–1
29	Virginia	0.5	5	5.5	–0.5	4.5	0	15	–3	–1
30	Idaho	5.5	1	5.5	0	2.5	0	14.5	–4	–1.5
30	Missouri	2.5	2.5	4	1	4.5	0	14.5	3	–0.5
30	Tennessee	1	3.5	3.5	2	4.5	0	14.5	5	0.5
33	Arkansas	7	1	3	–0.5	3.5	0	14	1	–0.5
33	New Mexico	5.5	1.5	2.5	1	3.5	0	14	3	0.5
33	Ohio	4.5	1	3.5	1	4	0	14	–4	–1.5
36	Montana	3.5	0.5	5.5	0	3	0	12.5	1	–0.5
37	Oklahoma	5.5	2.5	1.5	–0.5	3	0	12	2	1
38	Georgia	2	4	3	0	2	0	11	0	–1
38	Kentucky	1	1.5	4	0	4.5	0	11	–9	–4.5
40	Alaska	1	3.5	2	0	4	0	10.5	1	0.5
40	Indiana	3.5	2.5	2.5	0	2	0	10.5	0	0
40	South Carolina	1.5	2	3	0	4	0	10.5	1	0.5
43	Alabama	0	1	6	–0.5	3	0	9.5	0	0
43	Nebraska	0.5	1	6	–0.5	2.5	0	9.5	1	1.5
45	Mississippi	2	2	1.5	–0.5	3	0	8	–1	0
46	Kansas	0.5	1.5	3.5	0	1.5	0	7	0	–0.5
46	South Dakota	2	1	3.5	0	0.5	0	7	0	–0.5
48	Louisiana	0.5	1.5	2	0	2.5	0	6.5	–2	–1
48	West Virginia	–0.5	2	3	0	2	0	6.5	1	1
50	North Dakota	0	1.5	3	0	0.5	0	5	–1	–0.5
51	Wyoming	1	1.5	0	–0.5	2.5	0	4.5	0	0

Strategies for Improving Energy Efficiency

A variety of policy tools and program designs are available to state officials to strengthen efforts to save energy across multiple use sectors. The following list highlights examples of best practices by state policymakers seeking to improve energy efficiency performance by energy utilities, in the buildings and transportation sectors, and through appliance standards. We also highlight best practices that reduce legal and market barriers to investing in energy efficiency and expand participation in programs that achieve savings.

Establish and adequately fund an energy efficiency resource standard (EERS) or similar energy savings target. EERS policies set specific energy savings targets that utilities or independent statewide program administrators must meet through customer energy efficiency programs. They serve as an enabling framework for cost-effective investment, savings, and program activity. As states address evolving priorities such as decarbonization, cost, equity, and grid value, regulators in places like Massachusetts and New York are adjusting targets to incorporate multiple goals (e.g., fuel-neutral savings) that better align efficiency programs with electrification and GHG reduction objectives.

Examples: Arizona, Arkansas, Massachusetts, Michigan, Minnesota, New York

Adopt California tailpipe emissions standards and set quantitative targets for reducing vehicle miles traveled (VMT). Transportation consumes almost 30% of the total energy used in the United States. At the state level, a comprehensive approach to transportation energy efficiency must address both individual vehicles and the entire transportation system. A variety of state-level policy options are available to improve transportation system efficiency. These include codifying targets for reducing VMT and integrating land use and transportation planning to create sustainable communities with access to multiple modes of travel. While federal fuel economy standards are expected to go a long way toward helping to reduce fuel consumption, standards for model years 2022–2025 are currently under review and face an uncertain future. States that adopt California's tailpipe emissions standards will lead the way toward clean, fuel-efficient vehicles.

Examples: California, Massachusetts, New York, Oregon

Adopt policies to encourage and strengthen programs for income-qualified customers, and work with utilities and regulators to recognize the nonenergy benefits (NEBs) of such programs. States and public utility commissions (PUCs) can include goals specific to the low-income sector, either within an EERS or as a stand-alone minimum acceptable threshold. PUCs can further strengthen programs serving low-income households by designing cost-effectiveness tests that take into account the NEBs that these programs produce, including improved health, greater safety, and fewer trade-offs between energy and other necessities.

Examples: Illinois, Michigan, New Hampshire, Pennsylvania

Adopt updated, more stringent building energy codes, improve code compliance, and involve efficiency program administrators in code support. Buildings use more than 40% of the total energy consumed in the United States, making them an essential target for energy savings. Adopting mandatory building energy codes is one way to ensure a minimum level of energy efficiency for new residential and commercial buildings. Strategies such as energy performance standards, benchmarking and transparency policies, and financing tools to encourage deep retrofits are also critical, for addressing efficiency in the existing building stock.

Examples: California, Illinois, Maryland, Texas, District of Columbia, Washington, Nebraska

Expand state government–led initiatives and make them visible. States can establish sustainable funding sources for energy efficiency incentive programs, invest in energy efficiency–related R&D and demonstration centers, and lead by example by incorporating energy efficiency into government operations. In the latter area, they can reduce energy use in public buildings and fleets, and use energy savings performance contracts (ESPCs) to finance energy-saving projects. States can also work with utilities and community-based organizations to promote and coordinate energy code compliance training and workforce development programs.

Examples: Alaska, Connecticut, New York

Explore and promote innovative financing mechanisms to leverage private capital and lower the up-front costs of energy efficiency measures. Although utilities in many states offer some form of on-bill financing program to promote energy efficiency in homes and buildings, expanding lender and customer participation has been an ongoing challenge. States can pass legislation to increase stakeholder awareness and address legal barriers to the implementation of financing programs. A growing number of states are seeking new ways to maximize the impact of public funds and invigorate energy efficiency by attracting private capital through emerging financing models such as Property Assessed Clean Energy (PACE) programs and green banks.

Examples: Colorado, Connecticut, Minnesota, Missouri, New York, Rhode Island

Adopt cost-effective efficiency standards for appliances, equipment, lighting, and plumbing products. State appliance standards are a proven policy that lowers utility bills for customers and businesses, reduces pollution, and helps spur national standards. Even when state standards are not adopted at the federal level, adoption by just a few states can be enough to impact national markets. The Appliance Standards Awareness Project (ASAP) has outlined a menu of 18 recommended standards for 2019. Combined, they have the potential to provide more than $100 billion in savings to consumers.[1]

Examples: California, Colorado, Washington, Hawaii, Nevada

[1] Appliance Standards Awareness Project, *Update to "States Go First: How States Can Save Consumers Money, Reduce Energy and Water Waste, and Protect the Environment with New Appliance Standards*" (Boston: ASAP, 2018). appliance-standards.org/sites/default/files/write_up_of%20changes_to-the_analysis_for_2019%20Model%20Bill.pdf.

The Future of U.S. Electricity Efficiency Programs Funded by Utility Customers

Program Spending and Savings Projections to 2030

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Abbreviations

AEO	Annual Energy Outlook (EIA)
C&I	Commercial & industrial
Cooperative	Rural Electric Cooperative
DSM	Demand-side management
EE	Energy efficiency
EERS	Energy efficiency resource standard
EIA	Energy Information Administration
GWh	Gigawatt-hour
IOU	Investor-owned utility
IRP	Integrated resource plan
LBNL	Lawrence Berkeley National Laboratory
NEMS	National Energy Modeling System
PUC	Public utility commission
RPS	Renewable portfolio standard
TWh	Terawatt-hour

Executive Summary

Energy efficiency programs for utility customers are offered in every state. Spending on programs funded by electric utility customers grew by about 20 percent between 2011 and 2016, reaching ~$5.8 billion. Spending—and associated energy savings—have fluctuated over time with state goals, energy prices and market trends, among other factors. This study provides a forward-looking, bottom-up assessment of the potential impact of existing and likely policies and market conditions that promote or constrain future spending and savings for electricity efficiency programs funded by utility customers in all U.S. states.

We find that energy efficiency programs funded by utility customers have become a significant electricity resource in many states. This trend is expected to continue through 2030 and will have important implications for electricity system planning and operations. Electricity savings from these programs, and from complementary policies such as equipment standards and building energy codes, have contributed to modest or even no growth in electricity loads in many states in recent years. That affects the need for investment in new electricity infrastructure, across generation, transmission and distribution systems, and the impact of such investments on rates. Looking to the future, our analysis suggests that electricity efficiency programs funded by utility customers will continue to impact load growth at least through 2030.

Approach

The study includes three scenarios (low, medium and high cases) for 2030, with updated projections of spending and savings for interim years (2016, 2020 and 2025). The scenarios represent a range of potential outcomes given the current policy environment and uncertainties in the broader economic and state policy environment in each state. We reviewed relevant state statutes, regulatory commission decisions, and filings of electric utilities (investor-owned utilities, rural electric cooperatives and publicly owned utilities) and other efficiency program administrators. We also conducted more than 50 interviews with regulatory staff, energy efficiency experts, program administrators and other stakeholders to help inform scenarios and key assumptions.

Modeling future efficiency spending and savings

Our forecast of electricity efficiency program spending and savings to 2030 considers past and current performance of program administrators and key policy drivers in each state. These policy drivers include energy efficiency resource standards (EERS), statutory requirements that utilities acquire all cost-effective energy efficiency or include efficiency under state renewable portfolio standards, voluntary savings targets, public (or system) benefit charges that fund efficiency, integrated resource planning (IRP) requirements, demand-side management (DSM) plans and policies intended to reduce utilities' disincentives (e.g., decoupling) or provide a financial incentive to promote energy efficiency. Conversely, some states have adopted policies that effectively constrain the magnitude of available savings or spending on efficiency programs. We explicitly model policy constraints such as caps on program spending or rate impacts and statutes that allow large commercial and industrial (C&I) customers to opt out of efficiency charges and programs.

We distinguish among three timeframes: historical, policy period and post-policy period. In the historical period (2013-2016), we collect information on actual program spending and savings to establish an initial relationship between program costs and first-year electricity savings. The duration of the policy period (beginning in 2017) varies by state and depends on its specific policies.[1] In most states, the policy period does not include the entire study period. Thus, we define a post-policy period (from the time that key state policies expire to 2030) during which commitments have ended or are considerably less firm. For this period, we relied on interviews with state and regional experts and for the high scenario considered their view of best practices in the region to define a range of savings targets for each state.

Developing the Scenarios

The three scenarios represent alternative pathways for the evolution of electricity efficiency programs funded by utility customers during the post-policy period:

- The *medium scenario* largely represents a continuation of current practices and policies, subject to known policy and market constraints. We project that most states generally stay the course on policies and meet savings targets. Some states are expected to expand their commitment to efficiency based on recent legislation or regulatory commission decisions, while other states are expected to throttle back their commitment to efficiency.
- The *low scenario* represents a less prominent role for energy efficiency. States that are new to efficiency adopt a "go slow" approach; other states retreat from the current policy path—for example, EERS are not continued or are extended with lower savings targets, or states adopt new policies that constrain efficiency spending.
- The *high scenario* explores the possibility that states increase energy efficiency targets and budgets, driven by regional best practices that are adopted by other states in the area, and adopt favorable utility business models and savings targets set based on achievable energy efficiency potential.

Our study provides an analytically rigorous assessment of what we know and expect regarding the future of electricity efficiency programs funded by utility customers, based on current state policies and market drivers and constraints and a range of likely scenarios from the time these policies end through 2030. While this study does not envision or quantify the impact of potential new drivers and delivery mechanisms, we highlight emerging challenges faced by program administrators and policymakers and, in some cases, ways to address them (chapter 5).

[1] We compiled information on state policy drivers (e.g., DSM plan filings, IRPs, new legislation or major public utility commission decisions on electricity efficiency) through August 2018.

Key Findings

1. **Program Spending** - In the medium case, spending is projected to increase to $8.6 billion in 2030 compared to ~$5.8 billion in 2016, an increase of more than 45 percent (see Table ES-1). Projected growth in program spending tends to be front-loaded with increases concentrated in the first nine years (to 2025). This dynamic of front-loaded growth in spending is attributable to our methodological approach as well as our cautious assessment of efficiency market dynamics in the later years of our study period.[2] In the high case, annual spending increases to $11.1 billion in 2030, 90 percent higher than 2016 levels. In the low case, spending is projected to decrease in 19 states in 2030 compared to 2016 levels. National spending remains fairly flat, increasing to just $6.8 billion in 2030.[3]

Table ES - 1. Projected spending on electricity efficiency programs: Three scenarios

	Projected Spending ($ Billion)				Projected Spending as % of Retail Revenues			Average Annual Spending Growth		
	2016	2020	2025	2030	2020	2025	2030	2016-2020	2020-2025	2025-2030
Scenario										
Low		6.3	6.8	6.8	1.6%	1.4%	1.2%	2.2%	1.7%	0.1%
Medium	5.8	7.1	8.3	8.6	1.7%	1.8%	1.6%	4.3%	3.6%	0.6%
High		7.9	10.3	11.1	2.0%	2.2%	2.1%	7.1%	6.2%	1.4%

- **We project program spending as a share of electric utility retail revenues to be somewhat lower in 2030 than in 2016.** Electricity efficiency program spending in 2030 is projected to account for about 1.6 percent of retail revenues in the medium case, 2.1 percent in the high case, and 1.2 percent in the low case. Except for the high case, these levels are all lower than in 2016. Tracking spending as a percent of retail revenues provides an indication for the potential rate impacts of efficiency programs.
- **At the same time, total market activity leveraged by utility efficiency programs increases.** Projected spending by program administrators includes both administrative costs and incentives. Participating customers also typically pay for a portion of project costs—in some cases, a significant share. Thus, we also estimated total market activity leveraged by electricity

[2] For most states, we assume that when a binding EERS expires, savings targets will continue at levels consistent with the last year the standard is in effect. In addition, we have higher confidence in our modeling of spending (and savings targets) in the policy period compared to the post-policy period because we can typically rely on multi-year DSM plans. Finally, our modeling of the later years of our study period often relies on utility IRPs and their characterization of achievable potential for energy efficiency. Some utility IRPs are projecting reduced savings levels from 2025 on, which impacts our projections of spending from 2025 to 2030. Utility estimates of remaining achievable potential are often conservative. In their IRPs, some utilities have suggested that achievable potential for their efficiency programs is likely to be lower in the future due to tightening federal efficiency standards and transformation of certain end-use markets (e.g., increased market penetration of light-emitting diode (LED) lamps).

[3] Projected spending in 2030 ($6.8 billion) decreases in the low scenario if we account for the expected effects of inflation and report spending in real dollars.

efficiency programs, drawing upon results from the LBNL Cost of Saved Energy project.[4] For 2016, we estimated this value at about $11.6 billion. If we assume that the relationship between net participant costs and program administrator costs continues in the future, the total market size of electricity efficiency programs in 2030 would increase to $17.2 billion in the medium scenario and range from $13.6 billion in the low scenario to $22.2 billion in the high scenario.

- **Spending varies widely by region today, and regional shares of national spending are expected to shift over time.** The national results are driven by regional trends in program spending. In 2016, states in the West and Northeast accounted for 64 percent of national spending on electricity efficiency programs as energy efficiency services markets are relatively mature in these regions with many states implementing programs for decades, while states in the South and Midwest accounted for 36 percent. In 2030, these values represent the estimated shares of national spending in the low scenario. In contrast, in the high scenario, states in the South assume an increasingly prominent role, with spending projected to increase to $3 billion in 2030 compared to $1.0 billion in 2016 (see Figure ES-1). Thus, in 2030, the relative share of spending for states in the West and Northeast decreases to 55 percent of the national total, while states in the South and Midwest account for 45 percent.

[4] Projected spending by program administrators includes administrative costs and incentives. Total costs include costs incurred by participating customers. On a national basis, the total cost of saved electricity was double the program administrator cost of saved electricity between 2009 and 2015: $0.05/kWh vs. $0.025/kWh (Hoffman et al. 2018).

Figure ES - 1. Electricity efficiency program spending by region in 2016 vs. 2030 scenarios

- Midwest - Efficiency program spending in 2030 is driven primarily by four populous states (IL, MI, OH and MN) that have made long-term policy commitments in legislation. The future trajectory of efficiency spending in the region will be heavily influenced by policy constraints (e.g., opt-out policies, spending caps), long-term resource planning processes (e.g., MI and MN), and the extent to which utilities are motivated by business model policies to achieve higher savings goals.
- South - The range in spending in 2030 across the three scenarios is quite large ($1.3 to $3 billion) because utilities in many states have proposed savings goals in DSM plans or IRPs that are modest relative to the achievable potential. Thus, there is significant potential upside in the high scenario, as well as significant uncertainty regarding the extent to which policies that may constrain savings (e.g., large C&I customer opt-out) will spread to other states in the region.
- West - California accounts for more than 60 percent of spending in the region and we project that spending will increase by $330-480 million compared to 2016 levels, driven primarily by state legislation. Lower spending is projected in the Pacific Northwest states in all scenarios in 2030 compared to 2016, while we expect most Southwest states to sustain

long-term commitments to energy efficiency driven by state statute and favorable utility business models.[5]

- o Northeast - Efficiency program spending is projected to increase under all three scenarios, ranging between $2.1, $2.6 and $3.2 billion in the low, medium and high scenarios compared to $1.7 billion in 2016. All nine states in the Northeast have made strong policy commitments to energy efficiency and recent legislation in several states (NY, NJ, NH) increased savings (or spending) goals. Several of the historic leaders in the region (MA, RI, VT, CT) are projected to maintain or somewhat reduce spending levels on utility customer-funded programs due to anticipated saturation of efficiency potential, greater emphasis on complementary strategies (e.g., equipment standards, financing), concern about potential retail rate impacts, or state budget constraints.

2. **Program Savings** - In 2016, efficiency programs funded by utility customers saved 27.5 terawatt-hours (TWh) of electricity per year, equal to 0.74 percent of retail sales. Efficiency programs funded by customers offset at least 1 percent of investor-owned utility load in 23 states, with four states exceeding savings of 2 percent of sales (Hoffman et al. 2018). In the medium case, we project incremental annual electricity savings to increase very modestly to 28 TWh in 2030. Savings rise through 2025, and then decrease by 1.6 TWh by 2030. Savings are projected to decrease in most regions (except the South). The anticipated decline in relative program savings after 2025 across all scenarios is driven primarily by forecasts and views of program administrators that the potential to acquire cost-effective savings from voluntary programs is relatively lower because of increased reliance on complementary efficiency policies (e.g., equipment standards) and transformation of certain end-use markets (e.g., increased penetration of LEDs).

   - **Projected electricity savings increase significantly in the South by 2030.** The results are particularly striking in the high scenario, with projected savings significantly greater compared to other regions: 12.9 TWh in the South vs. 7.2, 8.3 and 9.2 TWh in the Northeast, Midwest and West, respectively (see Figure ES-2). Savings in the 17 states in the South account for 34 percent of the national savings from electricity efficiency programs in 2030 in the high scenario (compared to 19 percent in 2016). These results are driven by our assumptions. Several large states (FL, TX, TN) significantly increase their efficiency savings targets to levels that are closer to the achievable potential, program administrators in several states increase their efforts motivated by attractive utility business models (e.g., OK, NC, SC) or targets set in EERS legislation (MD, VA). However, savings as a percent of electric utility retail sales in 2030 remain higher in the Northeast (1.6 percent), West (1.2 percent) and Midwest (1.1 percent) than the South (0.7 percent).

[5] Although several utilities propose de-emphasizing efficiency in the long-term in their IRPs.

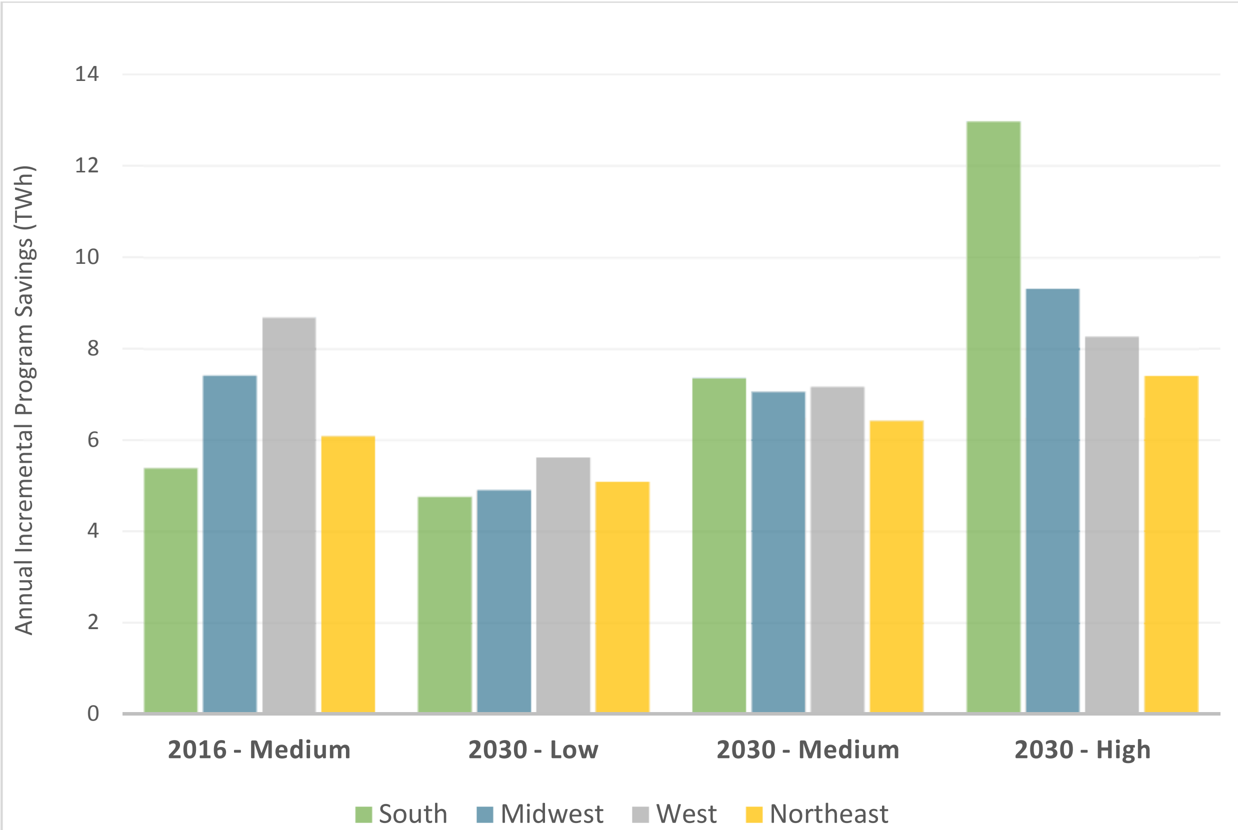

Figure ES - 2. Annual incremental program savings by region in 2016 vs. 2030 scenarios

- **Electricity savings from complementary strategies such as equipment standards will increasingly impact utility efficiency programs.** For the last decade, estimated annual savings from electricity efficiency programs were roughly comparable to annual savings from efficiency standards. However, for the 2017 to 2030 period, the average annual incremental savings from appliance, equipment and lighting standards may increase substantially compared to the previous period (e.g., 2002-2016). The increased savings from standards that take effect during the next five years means that it will be more challenging for efficiency program administrators to obtain cost-effective savings, particularly in the later years of our study period.

3. **Publicly Owned Utilities and Rural Electric Cooperatives** – For the first time, we explicitly model publicly owned utilities and cooperatives and project their future efficiency spending and savings. Spending by these types of utilities increases from $0.6 billion in 2016 to $0.8, $1.2 and $1.5 billion, respectively, by 2030 in our low, medium and high scenarios (see Table 4-4 in this report). Spending on electricity efficiency programs by publicly owned utilities and cooperatives accounts for 12 percent to 14 percent of national spending in the three scenarios and is concentrated in five states (CA, WA, TX, TN, MN), projected to account for 67 percent of efficiency spending by publicly owned utilities and cooperatives in 2030. Publicly owned utilities and cooperatives are projected to account for 14 percent to 19 percent of national savings in 2030 depending on the scenario.

Key Issues and Challenges

Key issues and challenges ahead for policymakers, regulatory commissions and efficiency program administrators that contribute to uncertainty in forecasting future pathways include largely external factors. At the same time, policy choices and regulatory and program practices also heavily influence efficiency pathways.

- **A changing economy and shifting policy objectives complicate forecasting of future electricity loads.** EIA projects that total retail electricity sales will increase at an annual growth rate of only 0.59 percent per year from 2016 to 2030. This projected growth rate is quite modest compared to historic growth rates for electricity sales (1.3 percent per year since 1990). This trend of slowly increasing or flat electric loads is driven in large part by the steady decline of energy intensity (i.e., the amount of energy used per unit of economic growth) for many years due to energy efficiency, structural changes in the economy and fuel economy improvements (EIA 2017).[6]

  However, several recent studies have explored the potential long-term impacts of “beneficial electrification” driven primarily by adoption of electric vehicles, heat pumps and select industrial applications on future electricity sales and peak demand. If states decide to promote electrification as a policy objective, then policymakers may have to reassess how they define energy efficiency policies and guidelines for efficiency programs, and utilities and other program administrators will have additional technical opportunities for investments in high efficiency technologies.

- **The cost of electricity supply options has declined.** In recent years, utilities and utility customers have benefitted from low natural gas prices and declining costs for natural gas-fired and renewable generation technologies. Going forward, low gas prices and increasing levels of renewable generation technologies with zero marginal cost translate into reduced efficiency program benefits (e.g., avoided energy and capacity costs), which may in turn constrain program budgets. Moreover, the evolving generation mix, current economics of supply-side options and evolving resource needs of utilities are changing the value proposition for energy efficiency resources. The result is a greater focus on time-varying value (e.g., to help meet peak system demand) and locational value (e.g., for load relief on distribution systems), more emphasis on controllable loads (e.g., to increase system flexibility), and more interest in bundling demand-side options such as energy efficiency, demand response, distributed generation and storage, and electric vehicles in order to provide various grid services.

- **State leadership drives institutional frameworks for energy efficiency.** Energy efficiency resources have distinctive characteristics that require state regulatory commissions to establish an institutional framework for effective oversight of utility customer-funded programs. These distinctive elements include: (1) the need for measurement and verification of savings; (2) program success dependent on customer acceptance and adoption, making stakeholder input

[6] EIA estimates that U.S. energy intensity has decreased from 12,000 to 6,000 Btu per dollar from 1980 to 2015 and will be 4,000 Btu per dollar in 2040 (EIA 2017).

on program design crucial; and (3) the need to align the utility's financial interest in pursuing cost-effective efficiency with a state's policy goals, given the disincentives that exist under traditional utility regulation. Many leading states have successfully grappled with these institutional and regulatory policy issues and a variety of approaches have proven to be effective. Thus, our high scenario assumes that in states that are newer to efficiency, legislatures and regulatory commissions provide leadership in defining energy efficiency policy objectives, establish roles and responsibilities for program administrators, and devote sufficient staff (or technical consultant) resources to effectively oversee acquisition of large-scale energy efficiency portfolios.

- **Program portfolios will need to evolve to continue to capture cost-effective electricity savings.** During the timeframe of this study and particularly in the later years (2025-2030), we expect that utilities and other program administrators will grapple with several significant challenges in developing a cost-effective portfolio of efficiency programs.
    - **New programs** - Program administrators will have to look for additional technical opportunities for saving electricity to offset their historic reliance on lighting programs.
    - **Large customer opt-out** - Program administrators in states that allow large C&I customers to opt out of paying for and participating in efficiency programs are likely to develop program designs that focus more on smaller and mid-size C&I customers. The cost of saved electricity for programs that target smaller C&I customers has historically been higher than programs for larger customers, putting upward pressure on program costs. For large C&I customers, program administrators may also focus more attention on Strategic Energy Management and the ISO 50001 standard to systematically track, analyze and plan energy use to continually improve energy performance — reducing operating costs and increasing productivity and competitiveness (State and Local Energy Efficiency Action Network 2016).
    - **Achieving deeper savings** - In states with more stringent efficiency savings goals for future years, program administrators will need to design and implement programs that can achieve deeper savings for participating customers and have a broader reach in terms of market penetration. Achieving higher market penetration rates includes targeting and reaching traditionally underserved markets (e.g., small commercial, multifamily, rental housing, non-owner-occupied commercial buildings) in far greater numbers than current practice. Program administrators also will need to design new, innovative programs that offer different strategies and services that are attractive to customers. Examples may include strategic energy management programs for industrial customers, greater reliance on building and industrial controls, programs that focus more on upstream/midstream market interventions (e.g., incentives to retailers, vendors), competitive procurement processes to meet distribution system needs that are open to aggregators that offer bundles of demand-side services and technologies, behavior-based programs using advances in data-based technologies and strategies, programs that combine technical assistance with incentives and financing (e.g., green bank, on-bill financing), and programs that integrate delivery of electric and gas efficiency programs. Program administrators can

also consider leveraging efforts of state and local governments and private providers to advance efficiency such as building energy benchmarking (Mims et al. 2017b) and Property Assessed Clean Energy (PACE) financing programs. Performance-based regulation also may play a role in utilities achieving deeper savings in the future, building on current practice in some states today (e.g., New York).

We include these examples to highlight that the portfolio of efficiency programs is likely to evolve significantly over the time horizon of this study. Program administrators and state regulatory commissions face emerging challenges, such as the increased impact of complementary strategies (e.g., standards), the decreasing costs of some supply-side resource options, and adapting the value proposition for energy efficiency to reflect changing utility system needs. The degree to which program administrators and states address these challenges is likely to heavily influence the longer term pathway for spending and savings on efficiency programs.

Integrated Resource Planning (IRP)

Integrated Resource Planning (IRP)

Key Definitions

An Integrated Resource Plan (IRP) is a plan that considers all reasonable resources to satisfy the demand for electricity during a specific period of time, including those relating to the offering of electric power and those relating to energy conservation and efficiency, while recognizing the obligation of compliance with laws and regulations that constrain resource selection.

Overview

Arizona's electric utilities complete an IRP every three years. Arizona Public Service (APS) and Tucson Electric Power (TEP) are regulated by the Arizona Corporation Commission (ACC). They complete their IRPs for a fifteen-year planning period. Salt River Project (SRP) is not regulated by the ACC. Its plan is for a twenty-year period. SRP completed its last IRP in 2017/2018. TEP and APS completed theirs in 2020. Those plans are then reviewed and "acknowledged" or not by the ACC. In 2017, the ACC did not acknowledge TEP or APS' IRPs. The 2020 plans are expected to be voted on in early 2021.

IRPs are important because they involve a stakeholder process that allows external parties to provide feedback on the direction the utilities will take in the next fifteen (or twenty) years. The IRPs are essential for providing a better understanding of the costs and environmental impacts of reliably providing electricity. An IRP takes a year or more to complete, including the stakeholder engagement process.

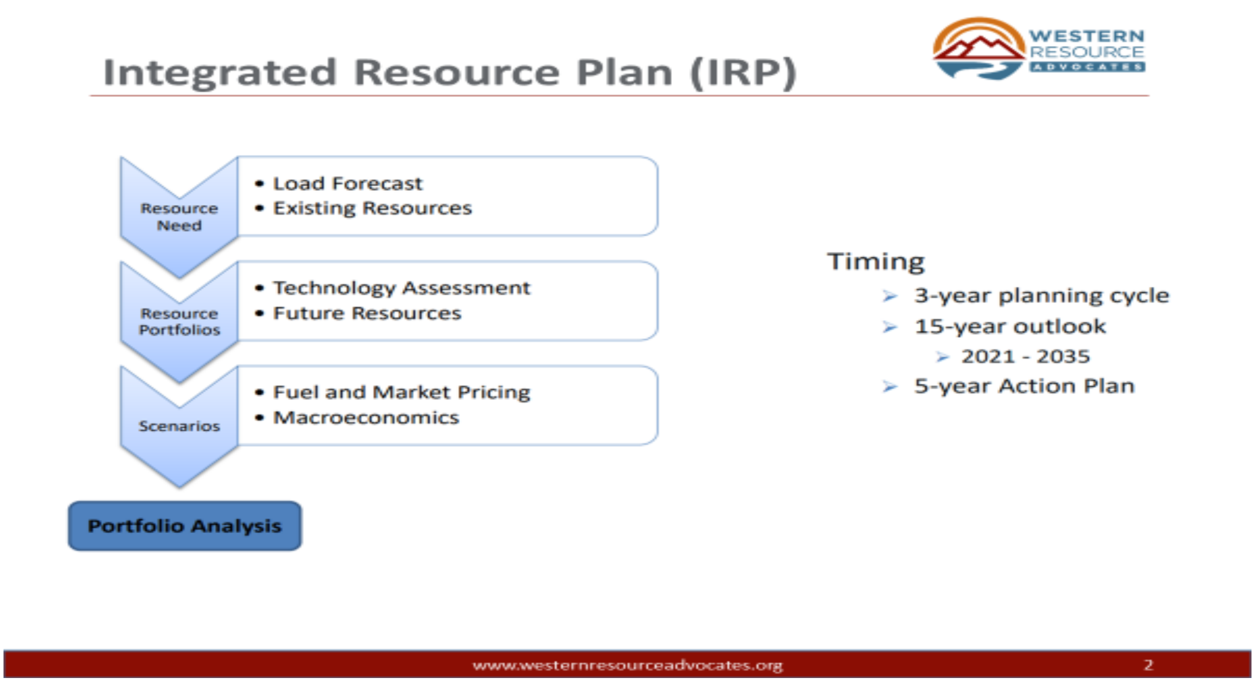

Image via TEP: https://www.tep.com/wp-content/uploads/TEP-2020-IRP-Public-Workshop-Final.pdf

Current Plans

In 2020, TEP announced they will no longer use coal to generate electricity by 2032, will use renewables to generate 70% of their electricity by 2035, and will reduce their carbon emissions by 80% from 2005 levels by 2035. TEP's 2020 IRP is consistent with those announcements and also does not include the addition of any new gas plants in the next fifteen years. Its Final IRP is available here: https://www.tep.com/wp-content/uploads/TEP-2020-Integrated-Resource-Plan-Lo-Res.pdf

Also, in 2020, APS announced it will use 100% clean, carbon free resources to generate electricity by 2050, it will stop using coal by 2031, and it will use renewables to generate 45% of its electricity by 2030. APS' Final IRP provides three possible portfolios, two of which have no new gas plants in the next fifteen years. Its plan is available here: https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/2020IntegratedResourcePlan062620.ashx?la=en&hash=24B8E082028B6DD7338D1E8DA41A1563

SRP completed its last IRP in 2018, with a planning period through 2037. SRP plans to incorporate their 2035 sustainability goals into their IRP. In 2019, SRP finalized their 2035 substantiality goals. Those goals include reducing their carbon emissions per megawatt-hour by 62% from 2005 levels by 2035 and by 90% by 2050. Their last IRP can be found here: https://www.srpnet.com/about/stations/pdfx/2018irp.pdf.

Policy Status

The ACC has been considering an update to their Energy Rules for two years. Proposed new rules could change the IRP process significantly. ACC Staff has proposed an updated rule and several ACC Commissioners have proposed their own amendments to those rules. A group of stakeholders has also proposed rule changes. The Staff rules, Joint Stakeholder proposal, and all Commissioner amendments are posted online at the ACC's website. The soonest the rule update could be completed is 2021. The docket number is RU-00000A-18-0284 and all documents can be found here: https://edocket.azcc.gov/Docket/DocketDetailSearch?docketId=21658#docket-detail-container2.

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Joint Stakeholder Comments on the Integrated Resource Plans of Arizona Public Service Company (APS) & Tucson Electric Power (TEP): Alternative Portfolios

Docket No. E-00000V-15-0094

February 2, 2018

Western Resource Advocates (WRA) , Arizona Utility Ratepayer Alliance (AURA), Diné CARE, To Nizhoni Ani, Western Grid Group, Arizona Interfaith Power and Light, Conservative Alliance for Solar Energy (CASE), Tucson 2030 District, Arizona Solar Energy Industries Association (AriSEIA), Efficiency First Arizona, National Association of Energy Service Companies (NAESCO), Solar Energy Industries Association (SEIA), Polyisocyanurate Insulation Manufacturers Association (PIMA), Arizona Community Action Association (ACAA), Southwest Energy Efficiency Project (SWEEP), and Our Mother of Sorrows Catholic Church

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Introduction

The following comments are provided by by Western Resource Advocates (WRA), the Arizona Utility Ratepayer Alliance (AURA), Diné CARE, To Nizhoni Ani, Western Grid Group, Arizona Interfaith Power and Light, the Conservative Alliance for Solar Energy (CASE), the Tucson 2030 District, the Arizona Solar Energy Industries Association (AriSEIA), Efficiency First Arizona, the National Association of Energy Service Companies (NAESCO), the Solar Energy Industries Association (SEIA), the Polyisocyanurate Insulation Manufacturers Association (PIMA), the Arizona Community Action Association (ACAA), the Southwest Energy Efficiency Project (SWEEP), and Our Mother of Sorrows Catholic Church regarding the 2017 Integrated Resource Plans filed by APS and TEP.

regarding the 2017 Integrated Resource Plans filed by APS and TEP.

As several stakeholders have indicated in their comments to this proceeding, the plans that were filed by APS and TEP are biased in favor of natural gas expansion, and biased against other resource options including renewable energy, energy storage, energy efficiency, and demand management. Importantly, we note that these other non-gas resource options are not only preferred by customers but also could lead to less overall cost and risk to customers going forward. As such, we describe here an Alternative Portfolio for both APS and TEP that we believe would provide a better path going forward in terms of meeting customer needs than the portfolios selected by APS and TEP in their 2017 IRPs.

Collectively the Alternative Portfolios would eliminate the need for over 4,520 MW of natural gas additions planned by APS and TEP. They would also put each utility on a path towards approximately 40% renewable energy by 2030, while investing in over 2,530 MW of new energy storage resources, and reducing peak demand by over 2,640 MW through energy efficiency and over 540 MW through demand management and demand response. Moreover, the Alternative Portfolios could save Arizona utility customers over $542 million when compared to the plans selected by APS and TEP.

Given limited budget and time constraints, the analysis presented here does not provide the full suite of technical modeling that could be pursued in developing an IRP. Nevertheless, we believe the analysis presented is sufficient to provide insight into the viability of the Alternative Portfolios and we recommend that they be thoroughly considered. We believe this provides a valuable "proof of concept" for what could be achieved while providing reasonable estimates of the potential costs and operational issues that may be encountered along the way. We welcome further discussion with APS, TEP and the Commission about these alternatives and any additional supporting analysis that may be needed.

Recommendations

As our analysis demonstrates, we believe the Alternative Portfolios presented here each provide a viable option that has many advantages over the portfolios selected by APS and TEP. In order to achieve the outcomes characterized by the Alternative Portfolios, we recommend several steps for the Commission to take:

- Establish a goal for APS and TEP to achieve at least 40% renewable energy by 2032. Include in this goal a set aside for renewable energy projects that provide a benefit to the Navajo and Hopi tribes of at least 300 MW for APS and 160 MW for TEP.

- In the IRP proceeding, require each utility to adopt a near term action plan that includes the following:
    - APS and TEP should each procure, respectively, 270 MW and 250 MW of energy storage by 2022.
    - At a minimum, APS and TEP should each continue to pursue energy efficiency resources at levels achieved in 2016, for each year from 2020 through 2032.
    - APS and TEP should pursue additional energy efficiency measures and advanced demand-management measures (beyond 2016 levels) that are specifically tuned to the evolving load shape (this should not include efforts being pursued through rate design or energy storage).
    - APS and TEP should pursue near-term procurement (by 2022) of a balanced mix of renewable resources including at least 575 MW of wind (375 for APS and 200 MW for TEP), 970 MW of solar PV (700 MW for APS and 270 MW for TEP), and 30 MW of forest biomass for APS.
- Direct the utilities to develop a quantitative assessment of the impact of electric vehicles on system energy needs and needed charging capacity.
- Consider the Alternative Portfolios presented here in any future review of or application for natural gas plant construction or acquisition.

Summary of the Resource Portfolios Selected by APS and TEP in their 2017 IRPs

APS' Selected Portfolio

In its 2017 IRP, APS selected a resource portfolio (the "Flexible Resource Portfolio" or "Selected Portfolio") that includes significant near-term natural gas resource additions, no increase in utility-scale renewable resources, significantly reduced demand-side management efforts, and almost no near-term energy storage resources. Specifically, the plan includes the following:

- Over 5,500 MW of new natural gas resources by 2032. More than 2,400 MW of these gas resource additions occur within the next five years including 1,500 MW of combined cycle additions and over 900 MW of combustion turbine additions.
- No new utility-scale renewable resources except for a small wind contract extension (16 MW-peak) in 2027.
- Peak demand reduction from energy efficiency is scaled back from approximately 100 MW annual incremental savings (or about 1,000 MW over 10 years) to 50 MW annually (or about 500 MW over 10 years).
- Only 3 MW of energy storage added over the next 5 years.

TEP's Selected Portfolio

In its 2017 IRP, TEP selected a resource portfolio (the "Reference Case") that includes significant near-term natural gas resource additions, significantly reduced demand-side management efforts, modest near-term renewable resource additions and modest near-term energy storage resources. Specifically, the plan includes the following additions over the next 15 years:

- Approximately 750 MW of natural gas capacity additions, including 336 MW of RICE units and 412 MW of combined cycle units. 600 MW of these additions occur within the next five years.
- Over 700 MW of new renewable resource capacity by 2032, including 100 MW of wind and 80 MW of utility-scale solar added within the next five years.
- Peak demand reduction from energy efficiency is scaled back from approximately 36 MW annual incremental savings (or about 360 MW over 10 years) to only 9 MW annually (or about 90 MW over 10 years).
- 100 MW of energy storage additions, with 50 MW occurring within five years.

In both cases, the utilities have selected portfolios that significantly expand natural gas resources in the near term. Meanwhile, both utilities significantly scale back their energy efficiency efforts relative to current levels, resulting in less energy savings and less peak demand savings going forward relative to current efforts. APS adds no meaningful new utility-scale renewable resources. In TEP's case, significant renewable energy resource additions are included, enabling 30% renewable energy by 2030.[1] However, most of these additions do not occur until much later in the planning horizon (i.e. after 2023). Both portfolios include meaningful energy storage resources; however, in APS' case most of these additions do not occur until after 2024.

We recognize that APS and TEP studied additional portfolios as part of their IRP analysis. However, we find that these other portfolios are not meaningfully different in terms of the expansion of natural gas resources. For example, the chart below illustrates that all seven of the portfolios analyzed by APS contain identical additions of natural gas combined cycle units (except for one minor change to one portfolio in the final year). Similarly, TEP did not appear to defer any gas generation resource additions in the portfolios that contained alternative resources.

[1] Figure according to TEP; the 30% renewable level may apply only to renewables' share of retail sales, not the full system generation.

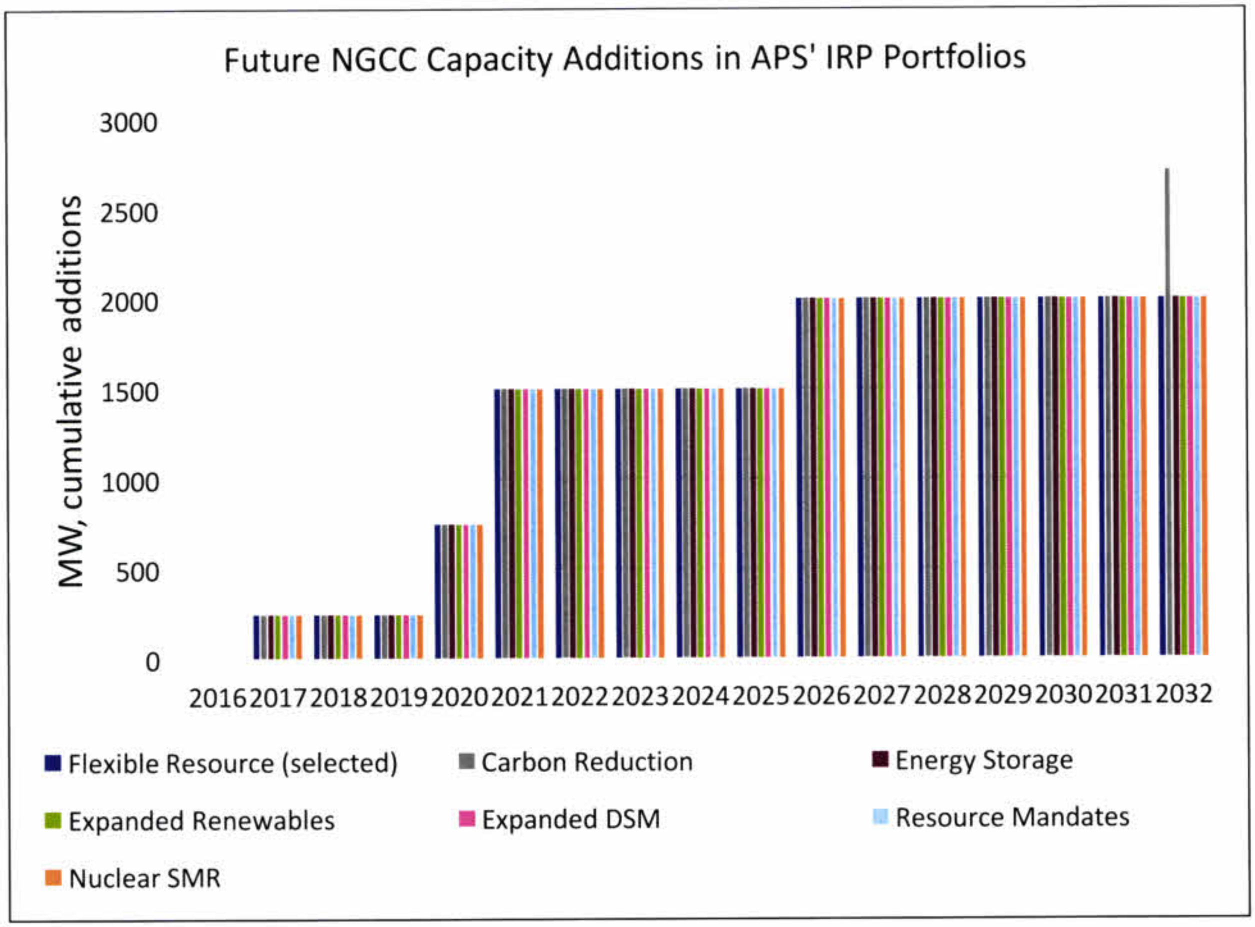

Figure 1. Comparison of NGCC capacity additions in portfolios analyzed in APS' IRP. Data source: APS 2017 IRP, Attachment F.1(A)(1) through F.1(A)(7).

Both portfolios appear to emphasize near-term natural gas resource additions instead of a combination of renewables, energy storage, and demand-side management. We do not believe this emphasis on natural gas matches customer preferences, moreover it represents a substantial increase in cost and risk borne by customers due to the uncertainty of future fuel commodity prices and the fact that fuel costs (and associated price risk) are directly passed through to customers. To better match customer preferences for clean energy and to better manage the cost and risk associated with natural gas additions, we developed an Alternative Portfolio for both APS and TEP for the Commission's consideration. These Alternative Portfolios are the result of a detailed analysis of the information provided in the APS and TEP IRPs, with specific modifications as described below.

Summary of the Proposed Alternative Portfolios for APS and TEP

APS Alternative Portfolio Summary

The APS Alternative Portfolio would reduce the addition of new natural gas resources over the next 5 years from over 2,400 MW to just 510 MW.[2] Over the long-term it would eliminate the need for over 3,875 MW of new natural gas additions when compared to APS' Selected Portfolio. In place of these gas additions, the Alternative Portfolio would include the following new resource additions:

- 1,105 MW of new large-scale renewable energy resources over the next 5 years, ultimately reaching more than 3,000 MW of new renewables by 2032. The near term additions would include 375 MW of wind, 700 MW of solar PV, and 30 MW of biomass. By 2032 wind additions would reach 1,105 MW and solar additions would reach 1,920 MW.
- New energy storage resources totaling 270 MW over the next 5 years and 2,100 MW by 2032.
- Incremental energy efficiency resources totaling 723 MW of cumulative peak demand reduction over the next 5 years and nearly 1,970 MW by 2032.
- Incremental new demand response and demand management resources totaling 168 MW over the next 5 years and over 450 MW by 2032.

As a result of these changes and others described herein we estimate that the total revenue requirement (net present value) for the APS Alternative Portfolio would be over $275 M less costly to customers over the 15-year period than the portfolio selected by APS.

Additionally, we estimate that the Alternative Portfolio would meet basic peak demand (MW) and energy (MWh) needs in each year of the planning horizon. We also estimate that the Alternative Portfolio would provide sufficient flexible ramping capability on APS' system to meet the maximum ramp events expected to occur in each year through 2032. Overgeneration events would continue to occur on a limited number of low load days throughout the year but could be managed through a combination of energy storage, modest renewable resource curtailment, and continued participation in regional markets.

[2] The remaining 510 MW consists of the Ocotillo Modernization Project, which we presumed was too advanced at this stage to be avoided.

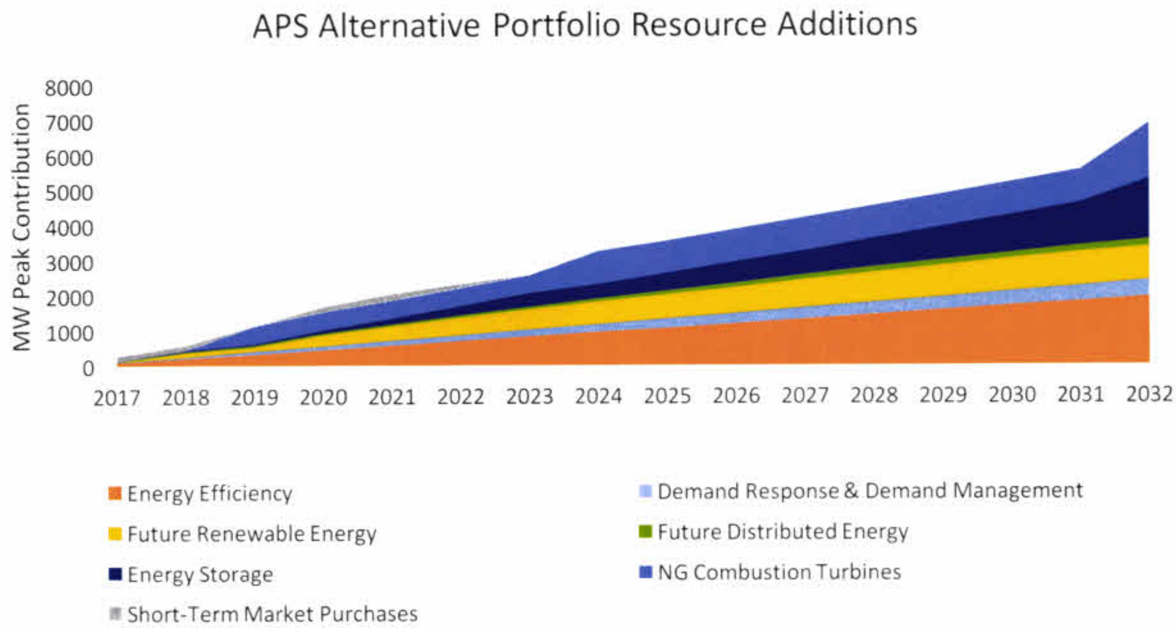

Figure 2. Capacity additions included in the APS Alternative Portfolio by MW-peak contributions.

Resource Additions (MW nameplate, incremental)	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2017 - 2022 Total**	**2017 - 2032 Total**
NG Combined Cycle	0	0	0	0	0	0	**0**	**0**
NG Combustion Turbine	0	0	510	0	0	0	**510**	**1,600**
Energy Efficiency	98	125	125	125	125	125	**723**	**1,973**
Demand Response	18	30	30	30	30	30	**168**	**466**
Wind (nameplate)	0	75	75	75	75	75	**375**	**1,920**
Solar PV (nameplate)	0	140	0	280	140	140	**700**	**1,834**
Energy Storage	0	45	0	50	75	100	**270**	**3,200**

Table 1. Near-term resource additions in the Alternative Portfolio for APS

TEP Alternative Portfolio Summary

The TEP Alternative Portfolio would reduce the addition of new natural gas resources over the next five years from over 600 MW to 100 MW. Over the long-term it would eliminate the need for approximately 650 MW of new natural gas additions when compared to TEP's Reference Case. One 100 MW RICE unit addition included in the Reference Case would be delayed from 2020 until 2022 while other RICE units and combined cycle resource additions would be eliminated. In place of these gas additions, the Alternative Portfolio would include the following new resource additions:

- 470 MW of new large-scale renewable energy resources over the next 5 years, reaching over 1,125 MW of new renewables by 2032.
- New energy storage resources totaling 250 MW over the next 5 years and over 430 MW by 2032.
- Incremental energy efficiency resources totaling 225 MW of cumulative peak demand reduction over the next 5 years and 675 MW by 2032.
- Incremental new demand response and demand management resources totaling 30 MW over the next 5 years (above existing levels) and 90 MW by 2032.

As a result of these changes and others described herein we estimate that the total revenue requirement (net present value) for the Alternative Portfolio would be $268 M less over the 15-year period than the portfolio selected by TEP.

Additionally, we estimate that the Alternative Portfolio would meet basic peak demand (MW) and energy (MWh) needs in each year of the planning horizon.

We estimate that the Alternative Portfolio would provide sufficient flexible ramping capability on TEP's system to meet the maximum 10-minute ramping events through 2024. Additional analysis may be needed to assess 10-minute ramping needs over the long term.

Due to time and resource constraints we were unable to analyze any overgeneration issues on TEP's system. However, we believe TEP will be able to employ strategies similar to those we describe for APS to manage this, including energy storage, renewable resource curtailment, and regional market participation.

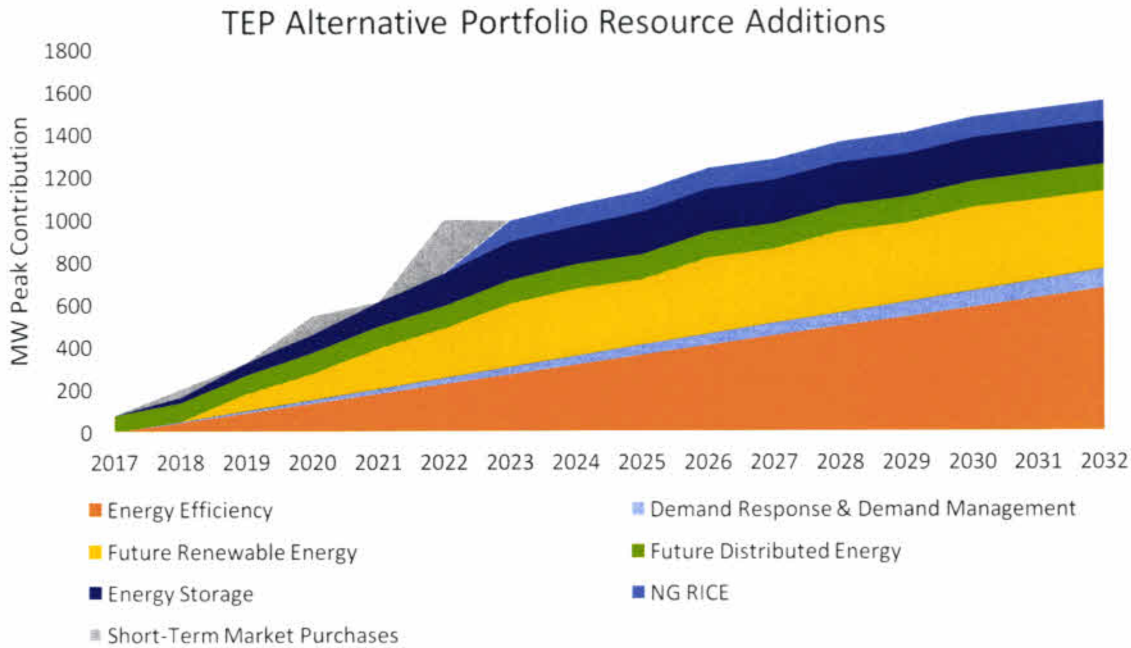

Figure 3. Capacity additions included in the TEP Alternative Portfolio by MW-peak contributions.

Resource Additions (MW nameplate, incremental)	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2017-2022 Total**
Natural Gas Combined Cycle	+0	+0	+0	+0	+0	+0	+0
Natural Gas RICE	+0	+0	+0	+0	+0	+100	+100
Incremental DSM (MW)	+0	+45	+45	+45	+45	+45	+225
Incremental DR (MW)	+0	+6	+6	+6	+6	+6	+30
Incremental Wind (nameplate)	+0	+50	+50	+0	+100	+0	+200
Incremental Solar PV (nameplate)	+0	+40	+50	+50	+50	+80	+270
Incremental Storage	+0	+25	+0	+90	+45	+90	+250

Table 2. Near-term resource additions in the Alternative Portfolio for TEP

Portfolio Construction

In each case, the development of the Alternative Portfolios began by using the Selected Portfolio or Reference Case Portfolio developed by APS and TEP as a starting point. We relied on the same energy and peak demand forecasts as those developed in the utility portfolios. We also relied on the same forecasts for distributed energy included in the utility portfolios.

We then removed or delayed several of the natural gas plant additions proposed in these portfolios. For APS, one exception to this was the 510 MW combustion turbine addition associated with the Ocotillo Modernization Project. Since this project is already at a very advanced stage, we presumed it could not be significantly altered. For TEP we delayed the addition of the first 100 MW of RICE units to 2022.

Next, sufficient additional resources were included to ensure that the portfolios met both annual peak demand (MW) needs and annual energy (MWh) needs for each year through 2032. To ensure a reasonable buildout, we limited additions of certain resources to a finite amount in each year. For example, wind additions were limited to no more than 100 MW in a single year for each utility. Several additional timing adjustments were also made, included the following:

- Extended one tolling agreement for APS.[3]
- Extended the PacifiCorp/APS diversity exchange.[4]
- Modified short term market purchases within 5 years.[5]
- Retired Cholla Generating Station in 2024 and Four Corners Generating Station in 2031.[6]

For existing thermal units, energy output was initially set to match the capacity factors modeled in the Selected Portfolios. Adjustments were then made to the energy ouptut from certain thermal units based on overall energy needs. In most years, this led to a reduction in output, reflecting the fact that additional energy efficiency and renewable resources will likely lead to reduced overall energy need from thermal generation in some years, thereby yielding additional fuel cost savings (or potential off-system sales).

Detailed load and resource tables and energy mixes are presented in Appendices A & B.

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[3] Similar to the method employed by APS in construction of its Selected Portfolio.

[4] See: https://www.azcentral.com/story/money/business/2014/09/11/aps-plans-close-one-four-generators-cholla-power-plant/15455255/

[5] Assumes short-term capacity purchase price of $50/kW-yr.

[6] Similar to TEP's Reference Case and APS' Coal Reduction Portfolio.

Energy+Environmental Economics

APS IRP Stakeholder Screening Tool

Final Analysis Results

August 16, 2019

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Xiaoxuan Hou, Consultant

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Purpose of stakeholder engagement initiative

E3 has worked with APS to engage stakeholders in a transparent scenario analysis exercise based on detailed analytics, with the objective of enabling stakeholders to test the impacts of various resource portfolios and policies before APS files its preliminary 2019 IRP

This initiative broadly encompassed three goals:

1. Develop an Excel-based tool that balances complexities of electric system modeling with time limitations and is directionally consistent with industry standard optimization models
2. Provide stakeholders with a more active means to participate in the portfolio planning process
3. Allow stakeholders to put forth a set of scenarios to study and directionally inform APS' development of its IRP

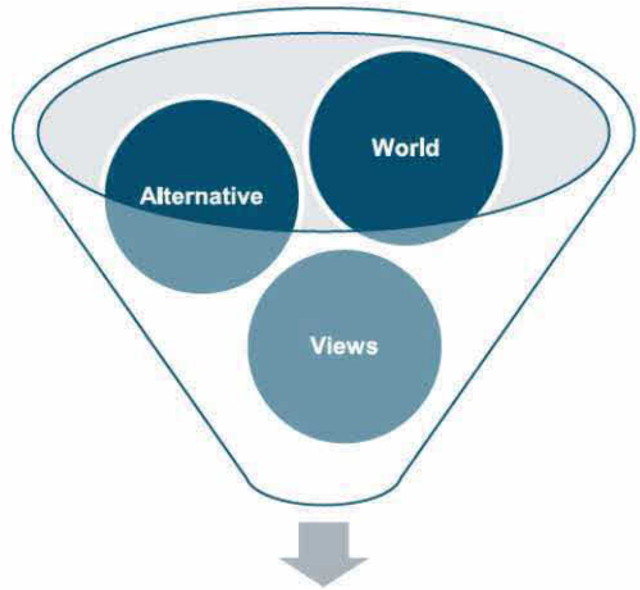
Guiding principles for the initiative

- **Transparency:** stakeholders can review IRP inputs and propose alternative future views to see how they affect key output metrics
- **Alignment:** analytics used to inform stakeholder discussion give results that are directionally consistent with more detailed planning models
- **Flexibility:** stakeholders can suggest alternative inputs (e.g., capacity additions or policy targets) to develop different scenarios
- **Accessibility:** stakeholders will have input into the scenarios modeled in the preliminary 2019 IRP

Overview of stakeholder screening tool

- **E3's stakeholder screening tool is an Excel-based model capable of designing and evaluating portfolios based on:**
  - Assumptions used in APS' IRP
  - Alternatives proposed by stakeholders
- **The tool provides useful directional results generally consistent with more rigorous planning models, enabling stakeholders to test a wide range of possibilities and build intuition**
- **By using the tool to explore a wide range of alternative scenarios stakeholders will have the opportunity to develop more focused input into IRP process**

Screening tool will allow stakeholders to prioritize input into scenario design



Reduced Set of Stakeholder Scenarios for Detailed IRP Modeling

Energy+Environmental Economics

Scenarios Analyzed

Building blocks for clean energy

+ **A technology-neutral approach to establishing future goals will provide optionality as opportunities for carbon reductions evolve, enabling utilities to choose the most affordable "building blocks"**

Building Block	Description
Nuclear	Maintain existing carbon-free generation
Renewables	Increase and diversify carbon-free generation
Fuel switching	Conversion from coal to gas (or other) generation
Clean imports	Utilize excess low-carbon electricity
Electrification	Electrify transportation sector and select building end uses
Energy storage	Load shifting/absorbing excess solar via energy storage
Demand management	Efficiency, demand response, & other demand-side measures

Four groups of scenarios explore different policy options

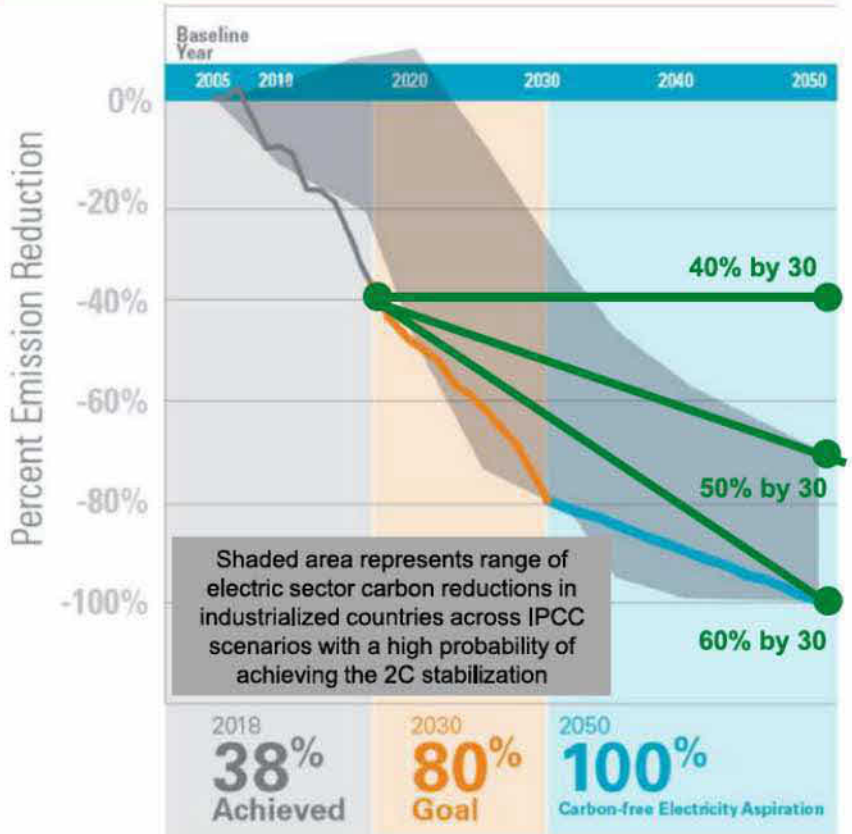
- **Scenarios modeled generally fall into four broad categories that affect the types of investments needed in each:**
  1. **Renewable Portfolio Standard (RPS):** portfolios designed to meet a kWh production quota for renewables, expressed as a percent of retail sales (30-50% RPS by 2030)
  2. **Clean Energy Standard:** portfolios designed to meet a kWh production quota for carbon-free resources (including nuclear & clean imports), expressed as a percent of retail sales (60-80% clean by 2030)
  3. **Carbon Target:** portfolios designed to meet a specific carbon goal (40-60% reductions by 2030)
  4. **Natural Gas Prohibition:** portfolios that prohibit investment in new natural gas infrastructure to meet future reliability needs
- **Stakeholders also designed a wide range of sensitivities to test assumptions on load growth, technology costs, and other key assumptions**

Science-based carbon targets

(Informed by Xcel Energy's analysis of science-based targets)

- Global climate modeling efforts have established a range of emissions reductions trajectories consistent with 2C climate stabilization
- Downscaling these estimates to specific geographies, sectors, and companies is a challenging exercise with no one-size-fits-all solution
- Reduction goals based on IPCC modeling that informed Xcel Energy's targets include a wide range that encompasses both Carbon-50 and Carbon-60 scenarios
- Notwithstanding uncertainty, modeling suggests considerable reductions are needed to achieve global climate stabilization

Science-based targets that informed Xcel Energy's future climate goals



Background figure source: Grounding Xcel Energy's Goals in Climate Science

Energy+Environmental Economics

Methods & Assumptions

Model inputs and outputs

Inputs

- Demand forecast
- Clean energy goals
- Existing resources
- Customer resources
- New resource options
- Fuel prices
- Hourly profiles
- Market prices

Model

- Cost minimization
- Determine costs via hourly economic dispatch
- Identify new build resources
- Satisfy planning reserve margin
- Satisfy hourly energy needs
- Satisfy clean energy goal(s)

Outputs

- Installed capacity
- Annual generation
- Imports
- Renewable curtailment
- Carbon emissions
- Generation cost

Analysis conducted in five-year increments

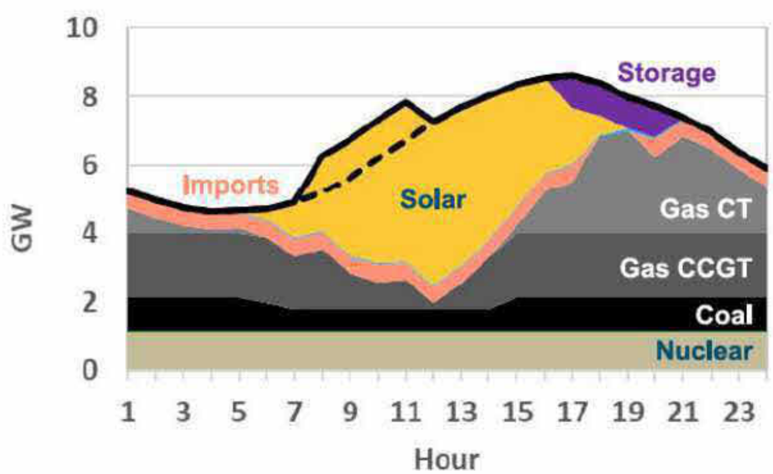
Model outputs reported in nominal dollars

Overview of model functionality

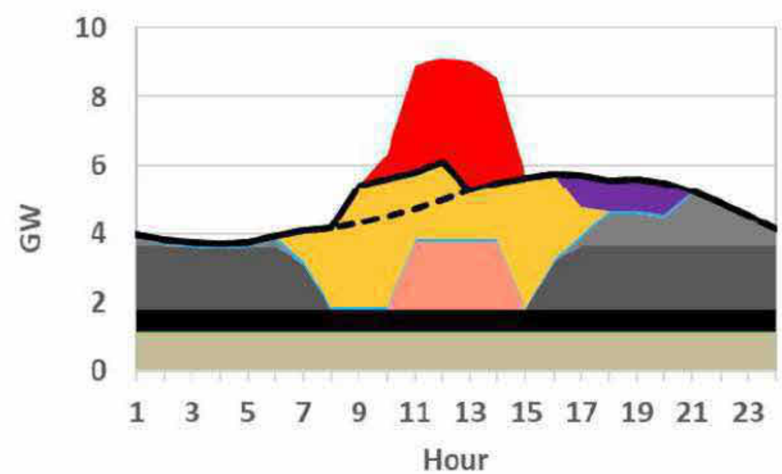
The screening tool constructs portfolios from a menu of resource options to meet specified clean energy and carbon goals while maintaining reliability:

- Renewables selected to provide carbon-free energy to meet user-specified goals
- Customer resources included in portfolio based on user forecast
- Energy storage is added on an economic basis to balance renewables & meet reliability needs
- Tracks energy imports and associated implied emissions based on imputed market heat rates
- Additional gas resources added to meet reliability when economic to maintain affordability

Example Summer Dispatch (2030)



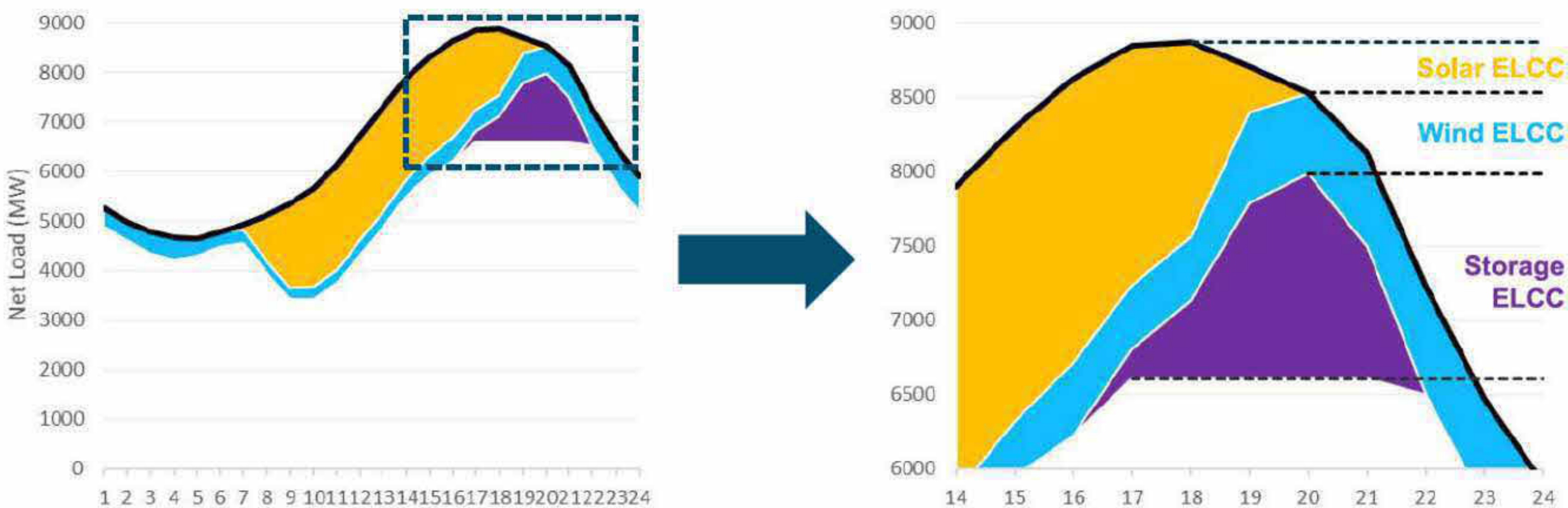
Example Spring Dispatch (2030)



Approximation of renewable & storage ELCC

+ **Planning reserve margin (PRM) requirement of 15% maintained to ensure reliability**
+ **Capacity accreditation for variable and use-limited resources under a PRM framework requires estimate of "effective load carrying capability," which captures limitations of each resource to meet reliability needs**
  - Typically determined through detailed loss-of-load-probability modeling
+ **In this model, ELCCs for renewables & storage are estimated based on their respective impacts on the net peak demand across the top 60 hours of the year (1% of hours)***

Approximation of ELCC Based on Impact on Net Peak Demand



** APS uses top 90 hours in its modeling; E3's assumptions and methodology based on benchmarking against APS analysis and other prior work*

Meeting reliability needs during peak periods

- **Resources needed to ensure reliability are based on expected peak demand plus a planning reserve margin**
  - Example of 2030 need: 10,000 MW peak + 15% reserve margin = **11,500 MW**
- **Contribution of different resources varies according to availability:**
  - **Nuclear, coal, and gas ("firm" resources)** that are available on demand contribute full capacity
  - **Solar, wind, and storage** contribute less than full capacity due to limits on availability

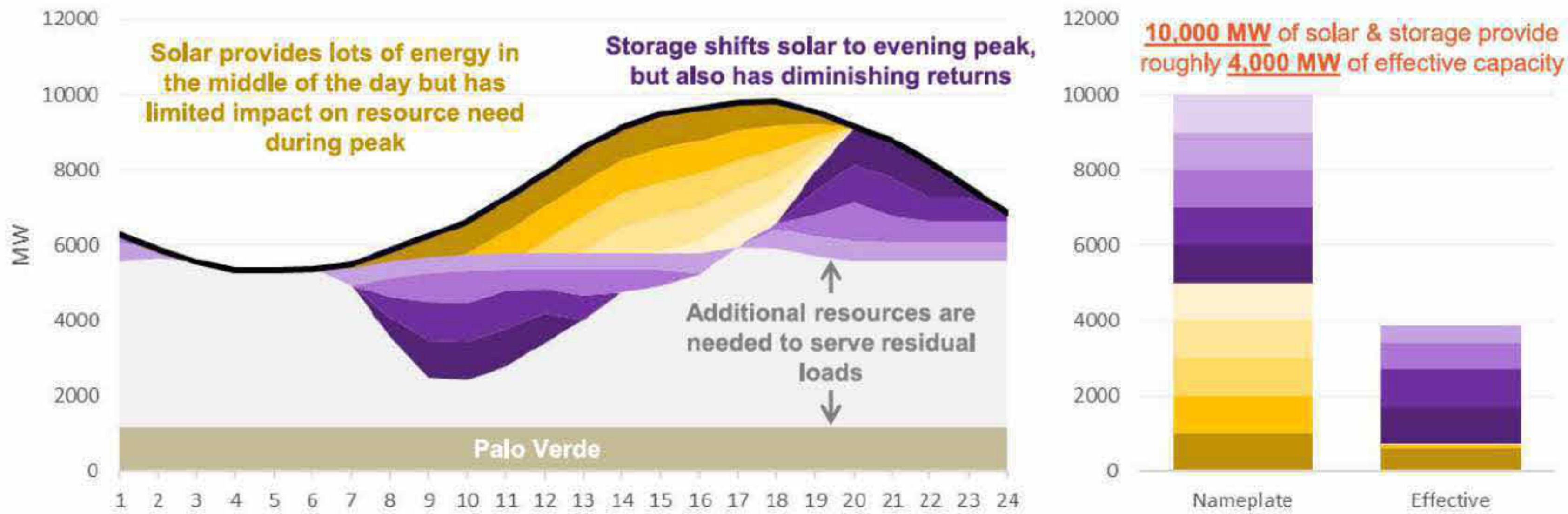


Figure is illustrative of model dynamics and not a model result

Key model inputs & assumptions

+ Inputs and assumptions used in this study provided by APS

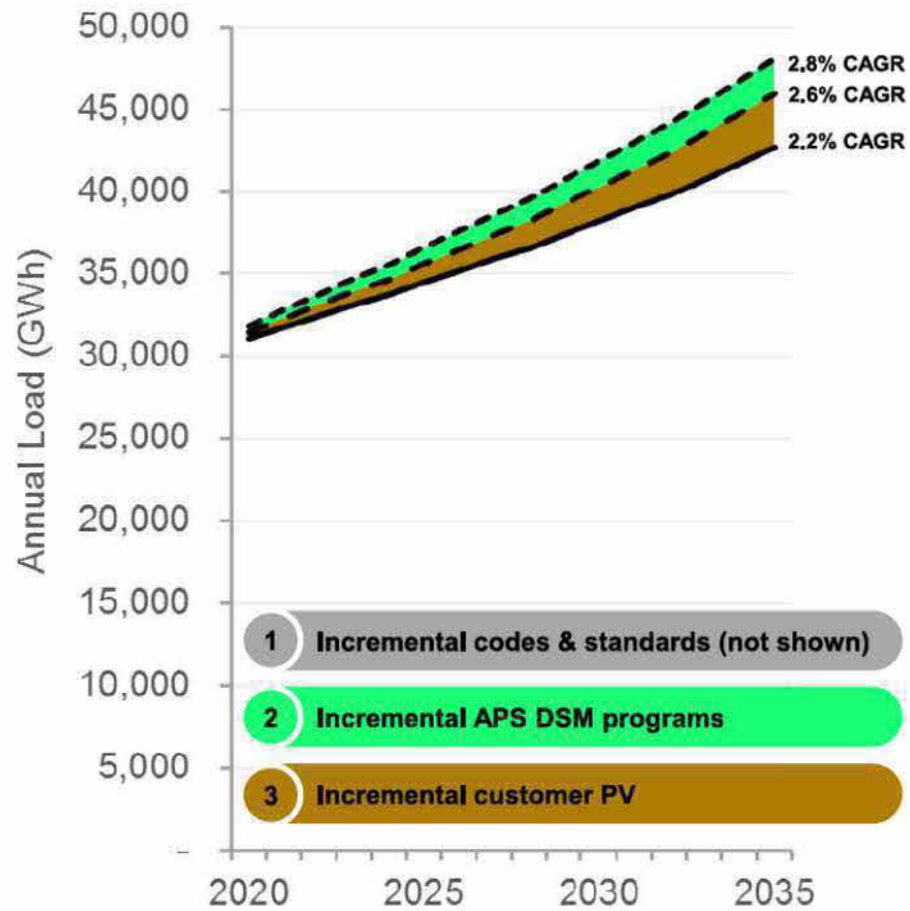
Category	Assumption
Load Forecast	• Energy demand (prior to impacts of APS programs) grows at a rate of 2.8%/yr
Energy Efficiency	• Energy efficiency program assumptions vary across scenarios • APS current DSM plan (~116 GWh/yr) reduces growth rate to 2.6%/yr • "High EE" scenario (239 GWh/yr) reduces growth rate to 2.3%/yr
Demand Response	• Demand response programs continue to grow at a rate of 25 MW per year
BTM Solar	• BTM solar increases from 1,269 MW in 2020 to 2,819 MW in 2035
Nuclear	• Palo Verde (1,146 MW) remains in service throughout analysis period
Coal	• Navajo Generating Station retired by 2019 • Cholla retired in 2025 for modeling purposes[a] • Timing of Four Corners retirement varies across scenario (2031 or 2038) • Take-or-pay fuel supply agreement results in low marginal cost of generation up to ~60% capacity factor through 2031 • Beyond 2031, minimum take-or-pay requirement removed and plant operated based on economics
Gas	• Existing APS-owned gas plants remain in service throughout analysis • CCGT tolling agreements totaling 1,600 MW expire in mid-2020s; 1,135 MW extended based on economics[b] • New gas CCGT and CT resources selected by the model based on costs in Appendix
Utility-Scale Solar	• Existing APS resources (~500 MW) remain in service; new First Solar project (65 MW) added in 2021 • New solar resources selected by the model based on costs (including integration cost of $2.50/MWh)
Wind	• Existing APS resources (~300 MW) remain in service • New wind resources selected by the model based on costs (including integration cost of $2.50/MWh)
Storage	• Planned 850 MW of utility-scale storage deployed by 2025 • Additional storage selected by the model based on costs
Fuel prices	• Uranium, coal, and gas prices aligned with APS 2019 IRP assumptions (see Appendix) • Carbon price begins in 2025
External market prices	• Hourly price forecast for California reflects aggressive policy goals & associated negative prices at a floor of -$30/MWh (escalating at inflation)

[a] APS is considering a biomass conversion of a Cholla unit; however, given that this is not final, we assume that the plant is retired for modeling purposes
[b] The extension of CCGT tolls is a simplifying assumption made for the purposes of E3's analysis and does not reflect a commitment by APS

Demand forecast (energy)

- **Robust growth in population and economic activity are expected to drive increased energy demand over time**
- **Efficiency assumptions reflect APS' current DSM plan**
- **Forecast load growth is partially offset by incremental DSM and DG PV**
  - Effects DSM and customer PV reduce expected growth rate by >1%/yr

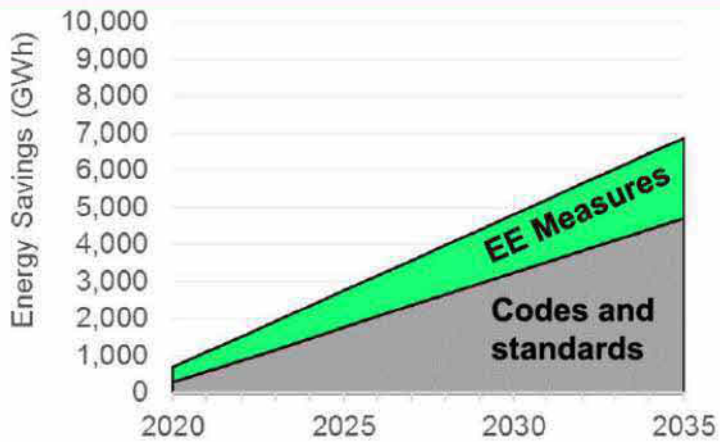
APS Demand Forecast



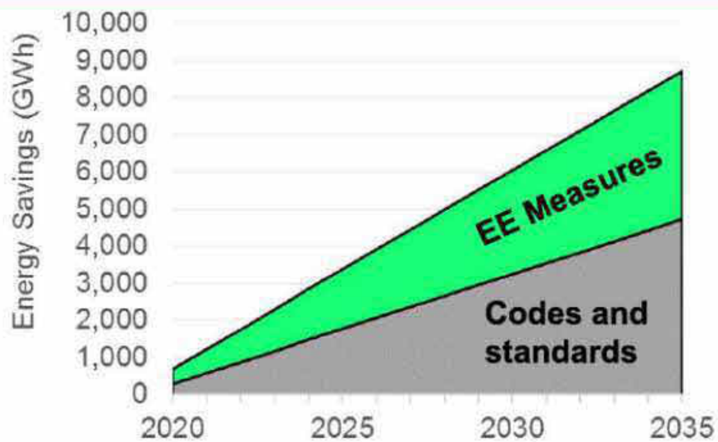
Energy efficiency levels

- Two energy efficiency levels were modeled: APS' current DSM program level and a higher EE level
- APS current DSM plan focuses on peak reductions & results in 116 GWh of incremental EE programs per year
  - 412 GWh of incremental EE per year when including codes and standards
  - Based on DSM measures in the APS 2019 DSM Plan (filed 12/31/18)
- Higher DSM level results in 239 GWh of incremental EE programs per year
  - 534 GWh of incremental EE per year when including codes and standards

APS Current DSM Plan



High DSM Sensitivity

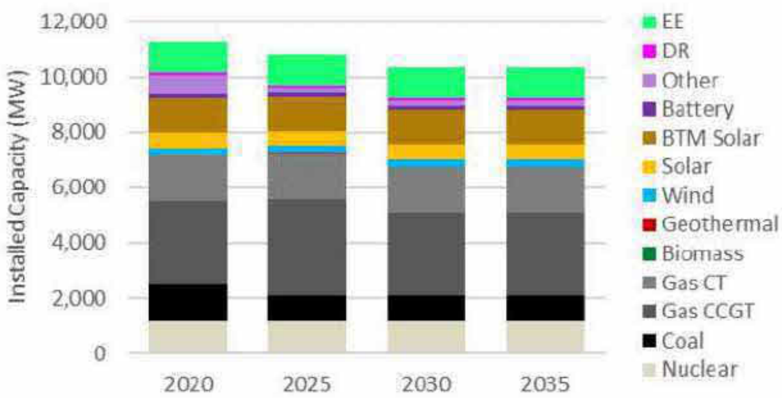


Additional analysis needed to characterize the cost impacts of achieving the High DSM scenario

Existing and planned resources

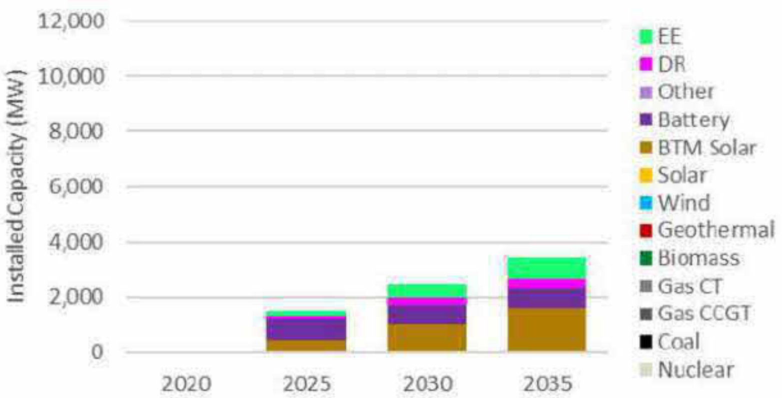
Existing Resources *(through 2020)*

- **Resource retirements and expiring contracts, combined with load growth, drive capacity needs through 2035:**
  - PacifiCorp seasonal exchange (480 MW) expires in 2020
  - Cholla (387 MW) retires after 2024
  - 1,598 MW of CCGT tolls expire between 2025 & 2030; this analysis assumes that 1,135 MW of CCGTs are renewed through the analysis horizon (assumption informed by preliminary analysis & sensitivities)



Planned Additions *(beyond 2020)*

- **APS DSM programs reduce 2035 peak by an additional 700 MW**
- **New DR deployed at a rate of 25 MW per year**
- **Battery storage added to meet APS' 850 MW goal by 2025**
- **Customer adoption of BTM solar results in additional 1,500 MW by 2035**



New resource options

+ **In each five years, the model selects which new investments to add to the portfolio on a least-cost basis while considering that (1) sufficient effective capacity must be available to meet reliability needs (i.e. PRM needs); and (2) sufficient "clean" energy is available to meet the corresponding policy goal**

Resource*	Option(s)	Capabilities
Utility-Scale Solar	• Single-axis tracking utility-scale solar with 33%+ capacity factor (pre-curtailment)	• Low cost source of intermittent generation • Limited capacity value beyond levels in existing portfolio
Wind	• New Mexico wind (49% capacity factor pre-curtailment) • Arizona wind (32% capacity factor pre-curtailment)	• Low cost source of intermittent generation • Small to medium additional capacity value
Energy Storage	• 4-hour lithium ion battery storage	• Source of flexibility to balance intermittency of renewables (esp. solar) and wholesale purchases from California • Initially large capacity value but declining impact with scale
Gas CT	• Frame combustion turbines	• Low-cost source of new capacity to meet reliability needs • Infrequent operations due to high heat rate
Gas CCGT	• Combined cycle gas turbines	• High-cost source of new capacity to meet reliability needs • Lower heat rate translates to more frequent operations

** Customer solar, demand response, and energy efficiency are treated as fixed resources and are not optimized in this study; see Slide 20 for a summary of assumptions. Future efforts may consider incorporating these options into optimization if data is available.*

Key takeaways from analysis

1. APS and Arizona are experiencing continued population and load growth which could drive significant investment needs across all scenarios analyzed
2. All modeled scenarios show that significant investment in new clean resources would be needed to achieve substantial carbon reductions
3. Scenarios with broadly-defined policies to encourage clean energy and carbon reductions provide more affordable and flexible options than prescriptive targets for specific technologies that narrow utilities' choices (e.g., RPS)
4. Palo Verde is critical to meeting future clean energy goals at low costs; replacing it with other resources would considerably increase customer costs and require substantial development time
5. Scenarios with early retirement of Four Corners show significant carbon benefits, but would require large replacement investments in the next decade to maintain reliability
6. Even in deep decarbonization scenarios, firm gas resources play a crucial reliability role but operate infrequently and at low capacity factors

Towards a clean low-carbon grid

- A balanced portfolio of resources will best enable a transition to a low-carbon grid while still meeting objectives of affordability and reliability
- The characteristics of each resource inform its role in a low-carbon grid
- Removing any single component from this picture could considerably increase the challenge of achieving objectives

Meeting grid needs in a clean, low-carbon grid

	Energy	Flexibility	Capacity	Description of Role
Nuclear	●	—	●	Provides stable source of firm carbon-free power
Renewables	●	○	—	Offers low-cost but intermittent carbon-free power
Storage	—	●	○	Balances renewable variability, provides some capacity
Gas	—	○	●	Serves as low-cost standby resource to meet reliability
DSM	○/●	○/●	○/●	Offers dynamic customer response to grid needs

How **clean** is my portfolio? (Energy)

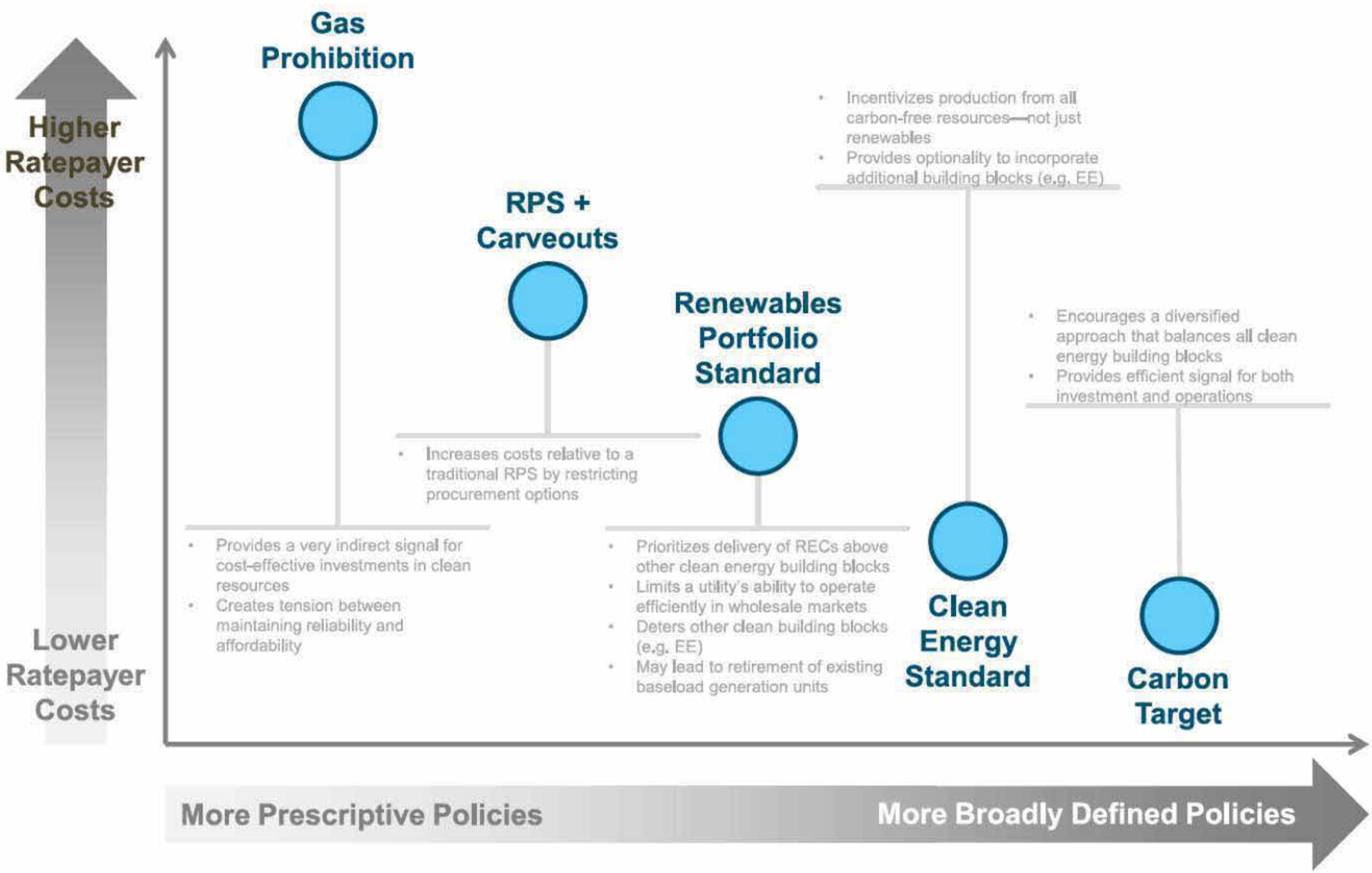
How **reliable** is my portfolio? (Capacity)

● **Primary purpose(s)**

○ *Secondary purpose(s)*

— *Small or negligible contribution*

Defining a spectrum of policy options



THE UNIVERSITY OF ARIZONA

CLIMATE AND TEP RESOURCE PORTFOLIOS – EMISSIONS REDUCTION AND CUMULATIVE CARBON BUDGETS

TEP IRP Public Workshop – May 20, 2020

Ben McMahan, Asst. Research Professor, Climate Assessment for the Southwest (CLIMAS), Arizona Institutes for Resilience

Will Holmgren, Asst. Research Professor, Hydrology and Atmospheric Sciences

University of Arizona

CLIMAS Climate Assessment for the Southwest

ENVIRONMENT

1. BACKGROUND AND CONTEXT

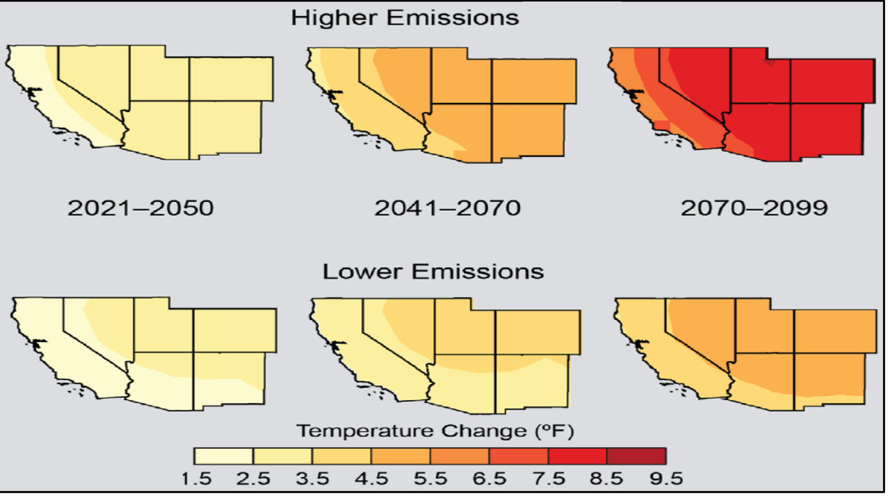
2. GREENHOUSE GAS REDUCTION GOAL PLANNING REPORT

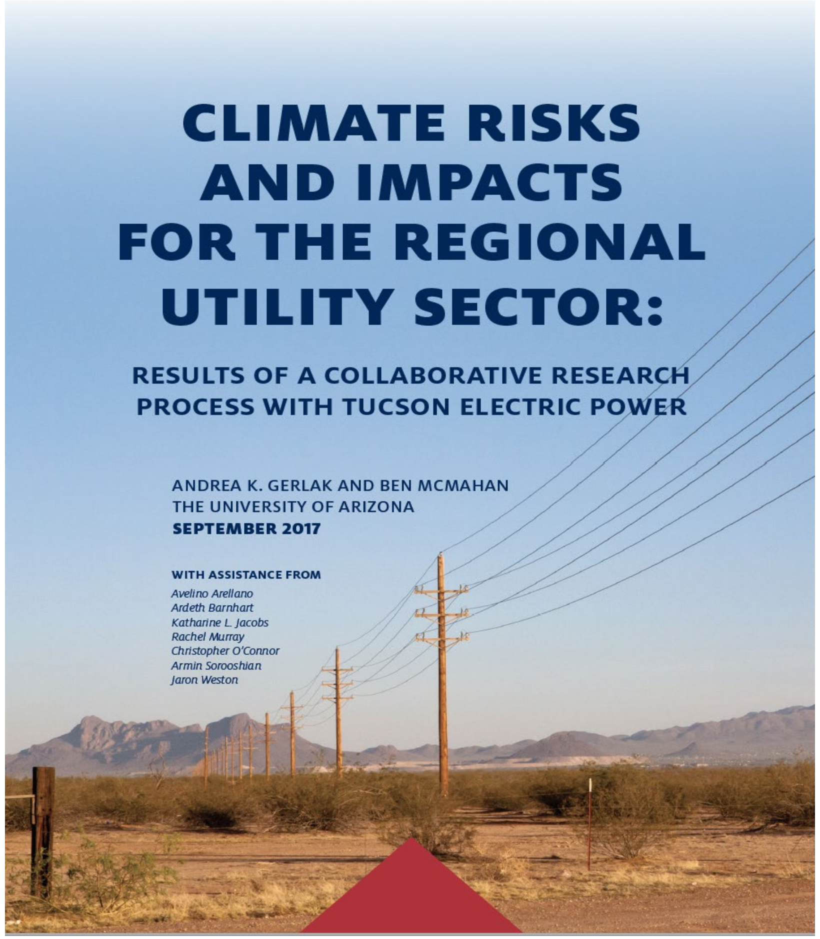
3. SCENARIOS FOR CARBON REDUCTION: FRAMEWORK AND BACKGROUND

4. TEP IRP PORTFOLIOS: GHG REDUCTION AND CUMULATIVE CARBON BUDGETS

BACKGROUND AND CONTEXT

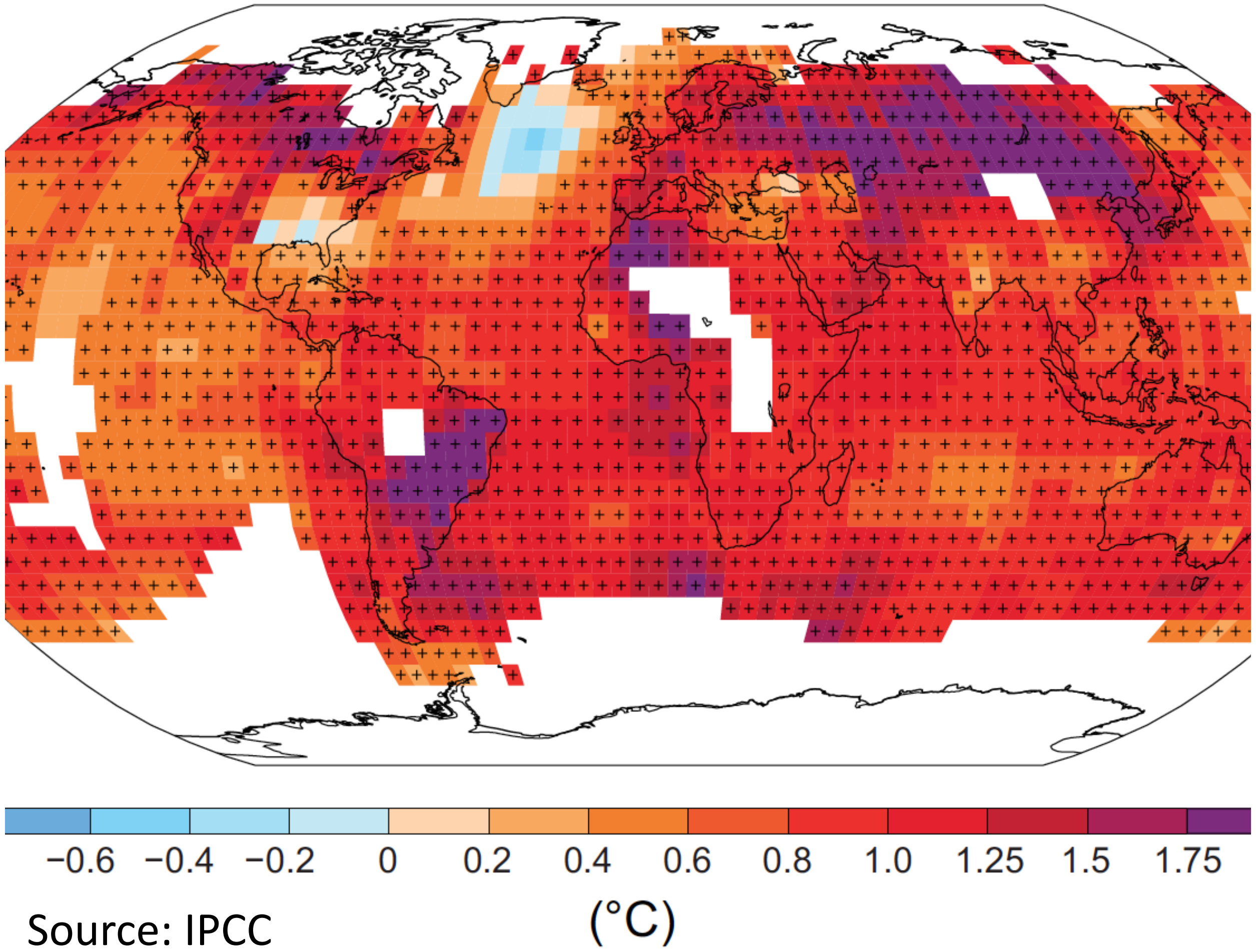
ARIZONA BUSINESS RESILIENCE INITIATIVE (ABRI)





	Qualitative Risk Assessment							
	Description of Key Risk/Cost	Timescale & Intensity Short	Medium	Long	Probability	Confidence	Intervention Potential	Perception of Risk
Wildfire	Fire Risk - Proximity to Critical Infrastructure	MED	HIGH	HIGH	LOW	MED	HIGH	HIGH
	Buffel Grass Infestation & Wildfire Risk	MED	MED	MED	MED	HIGH	HIGH	HIGH
	Fire Behavior & Changing Seasonality	LOW	MED	MED	HIGH	HIGH	LOW	LOW
	Debris Flow & Post-Fire Flooding	LOW	LOW	LOW	LOW	LOW	LOW	LOW
	Particulate Matter Concentraion - Smoke & Ash	LOW	MED	MED	LOW	LOW	LOW	LOW
Heat & Climate	Gradual Warming - Increased Peak (daily) Load/Demand	LOW	MED	HIGH	HIGH	HIGH	HIGH	LOW
	Gradual Warming - Infrastructure Wear (O&M Costs)	LOW	LOW	LOW	LOW	MED	MED	LOW
	Extreme Heat - Transmission Efficiency, Reduced Capacity Factor	LOW	LOW	MED	LOW	LOW	LOW	LOW
	Extreme Heat - Market Competition - Regional Outages	LOW	MED	MED	HIGH	HIGH	MED	MED
	Gradual Warming - Social/Community Vulnerability (quality of life)	LOW	MED	MED	MED	MED	LOW	MED
	Gradual Warming - Changing Seasonal Demand	LOW	MED	HIGH	MED	MED	HIGH	MED
Water Availability	Regional Drought & CAP Water Restrictions (e.g. 1075')	LOW	MED	HIGH	LOW	MED	LOW	HIGH
	Regulatory Impacts of Water Resource Management (AMAs)	LOW	LOW	MED	MED	MED	LOW	LOW
	Regional Drought and Water Availability	MED	HIGH	HIGH	HIGH	LOW	MED	MED
	Water Availability/Competition - PHX Basin	LOW	MED	HIGH	HIGH	HIGH	MED	MED
	Water Availability/Competition - Tucson Basin	LOW	LOW	LOW	LOW	HIGH	MED	MED
Air Quality	Increased Dust, Particulate Matter, & Erosion	LOW	MED	MED	LOW	HIGH	LOW	LOW
	Increased NO.x and O3 (EPA Attainment Status in Phoenix Basin)	LOW	LOW	MED	LOW	MED	LOW	HIGH
	Particulate Matter Concentraion - Smoke & Ash	LOW	LOW	LOW	LOW	LOW	LOW	LOW
	Increased GHG Emissions/Methane (Federal Regulatory Framework)	LOW	MED	MED	MED	HIGH	MED	HIGH

State of the Climate Science



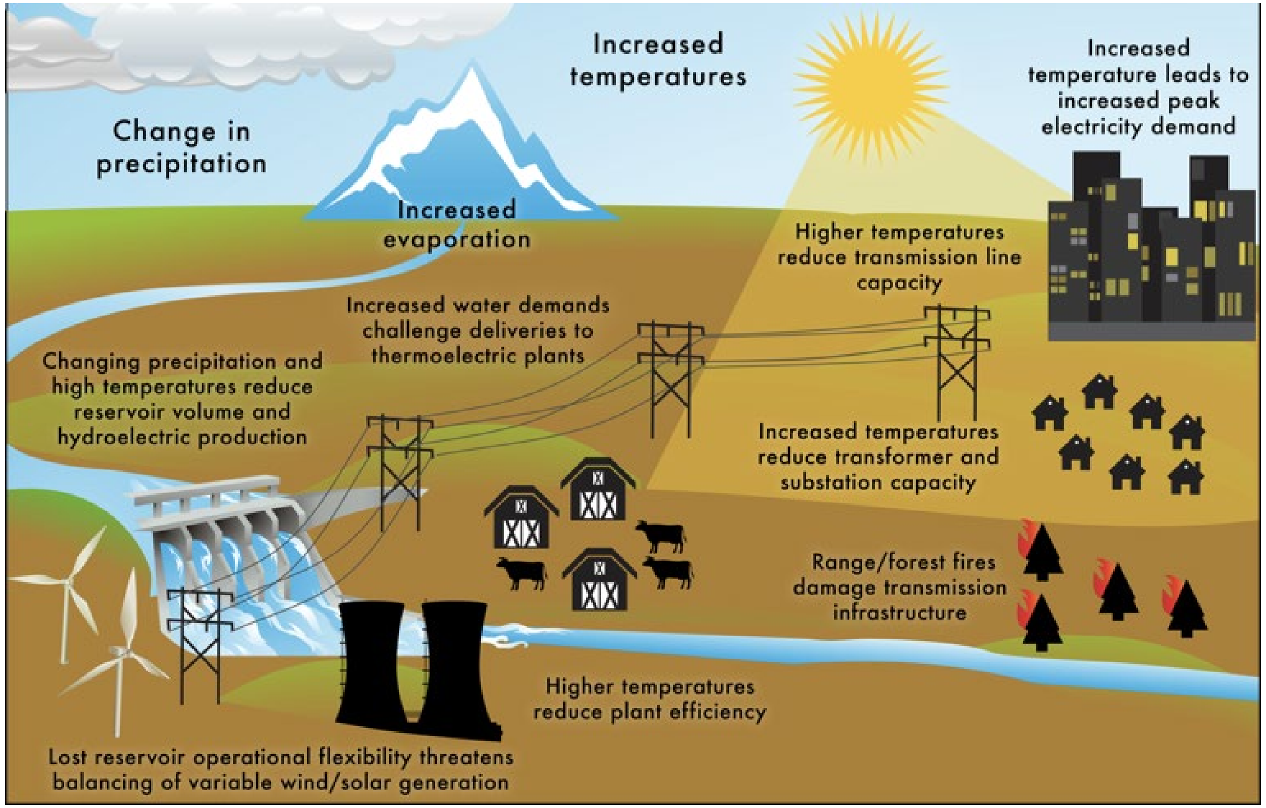
Source: IPCC

Since pre-industrial times, **CO_2 concentrations have increased by 40%**.

Warming of the climate system is "**unequivocal**" and many of the changes to the system have been "**unprecedented** over decades to millennia".

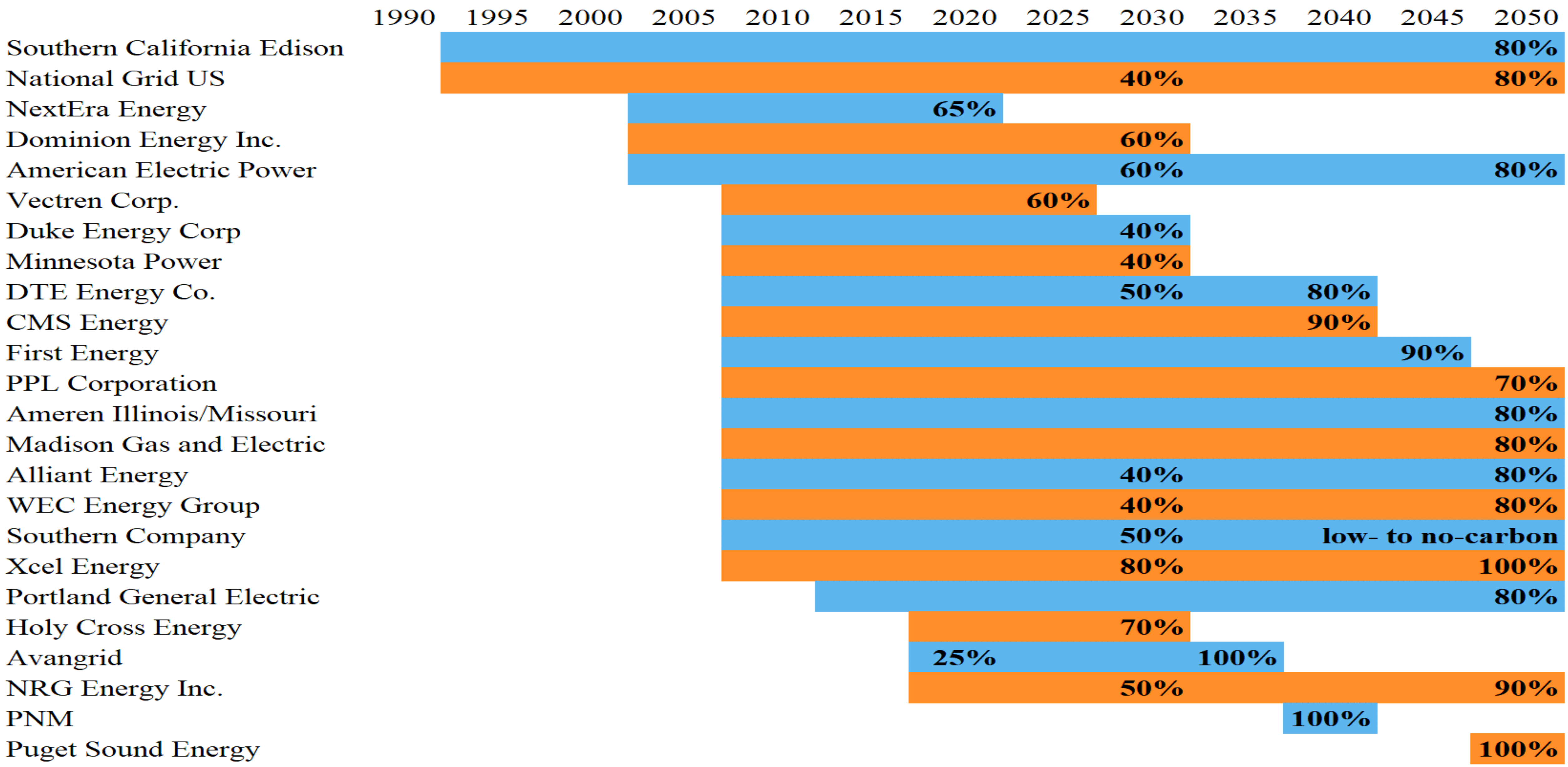
Human activity has been the **dominant cause** of global warming since the mid-20th century.

Projected impacts for the U.S. Southwest



Source: National Climate Assessment

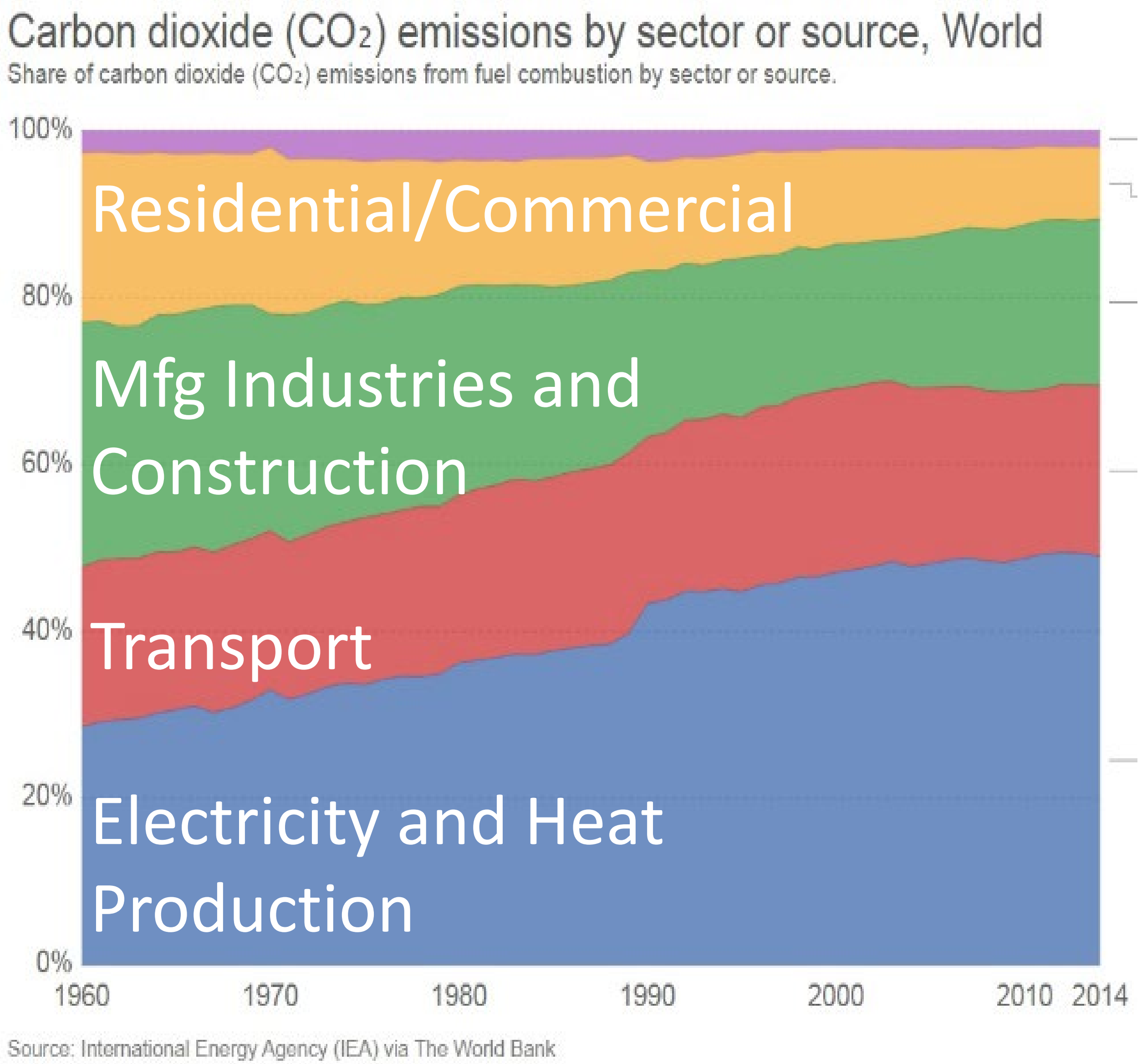
Select U.S. utilities' emissions reductions targets



What can we learn from this?

- Most investor-owned utilities frame targets as a % reduction below a baseline before an end date.
- Diversity of targets and starting points makes comparisons difficult.
- The **anchor among all the targets** is the extension to the **US's NDC**: "80% reductions under 2005 emissions by 2050".

Science Based Targets Initiative



- GHG reduction target is "**science-based**" if it is in line with the level of decarbonization necessary to **limit warming to 1.5 C** or **well below 2°C** compared to pre-industrial levels.

SCIENCE BASED TARGETS

DRIVING AMBITIOUS CORPORATE CLIMATE ACTION

CDP DISCLOSURE INSIGHT ACTION

UN GLOBAL COMPACT

WORLD RESOURCES INSTITUTE

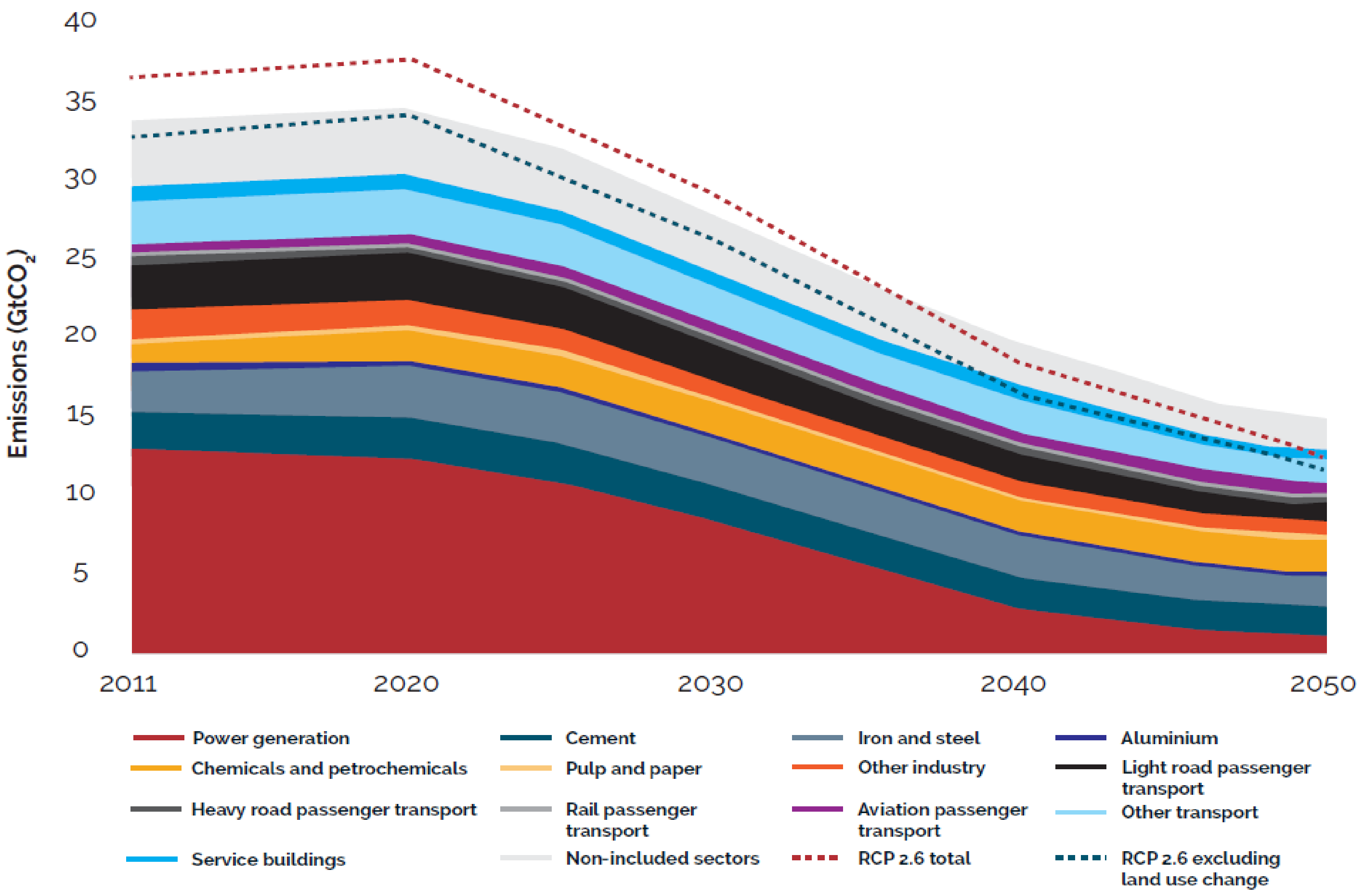
WWF

Sectoral Decarbonization

Reduction Framework – Overall and by sector

Power Generation: 80->90% reduction in 2005 emissions by 2050 (well below 2C)

Figure 8. Sectoral breakdown of absolute CO2 emissions budget, 2011–50



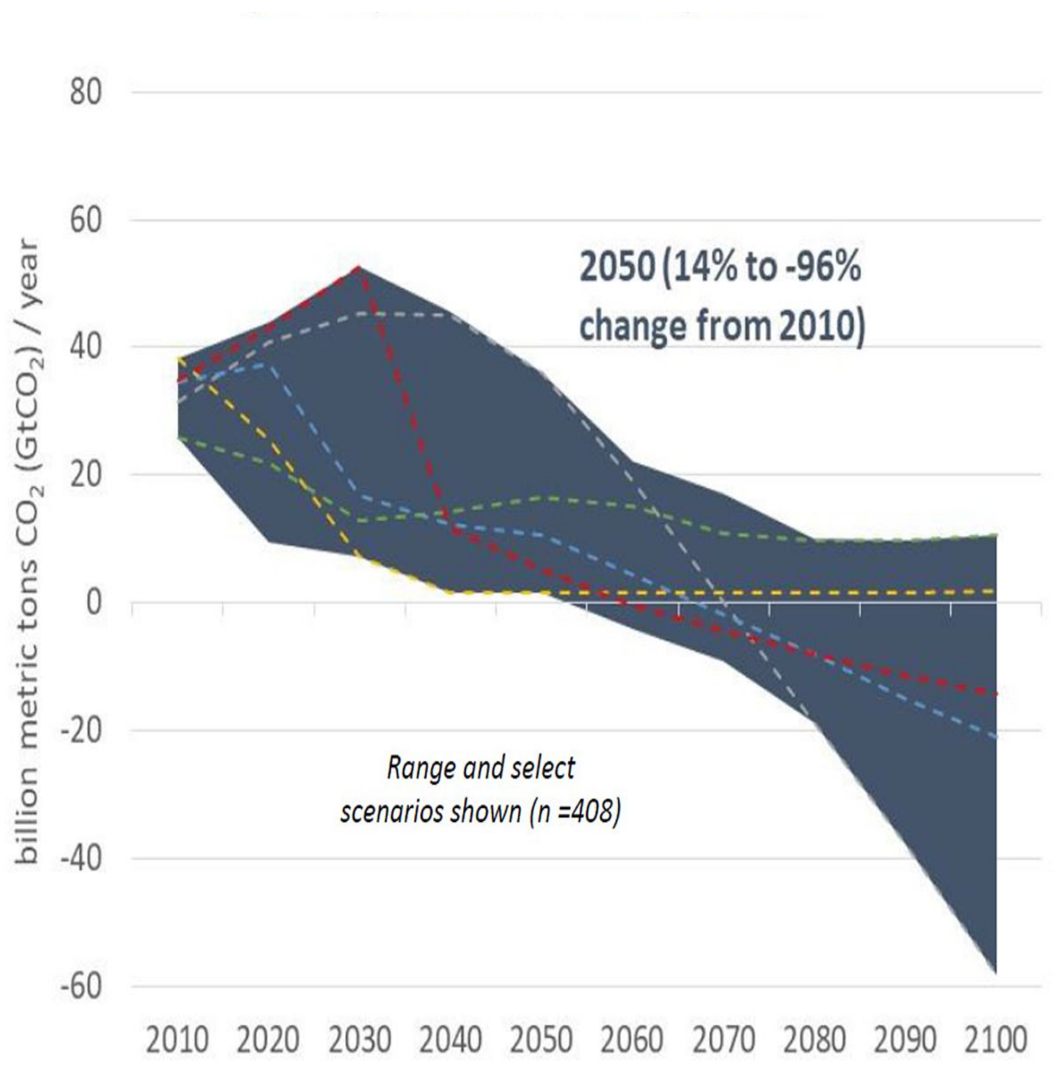
Source: IEA ETP 2DS 2014.

SCIENCE BASED TARGETS

DRIVING AMBITIOUS CORPORATE CLIMATE ACTION

Electric Power Research Institute

4 insights for creating emissions reductions targets



1. Use individual perspectives to identify the **relevant uncertainties** and define the **company-specific context**;
2. Base climate strategies on **scientific understanding of climate goals** and the companies' relationship to these goals;
3. Choose a cost-effective target, **which will differ across companies**; and
4. Robust strategies are those that are **flexible and that make sense in different future contexts**.

Clean Energy

Clean Energy

Key Definitions

Clean Energy comes from an energy resource that operates with zero net carbon dioxide emissions.

Overview

An energy transition is underway globally, in the United States, and in Arizona. The use of fossil fuels to produce energy, including electricity, has led to extensive pollution, excessive water use, and emissions that result in climate change. Countries, states, counties, cities, and even corporations have made announcements in the last couple of years committing to reduce their carbon emissions or increase their use of clean energy resources.

You can view a list of such commitments here:

Sierra Club: https://www.sierraclub.org/ready-for-100/commitments;

Natural Resources Defense Council: https://www.nrdc.org/resources/race-100-clean; and

Ceres: https://www.ceres.org/sites/default/files/reports/2019-08/Ceres_ElecSectorClimateStratAssess_Update_081319.pdf.

Climate change poses risks of increased temperatures, drought, and wildfires in Arizona. The Intergovernmental Panel on Climate Change (IPCC) states that to keep to a 1.5°C increase in global temperature, economy-wide carbon emissions must be net zero by 2050, but earlier reductions are also needed, including a 45% carbon reduction by 2030. The electric sector is the simplest major sector of the economy to decarbonize, so it should go furthest fastest. This is because the technology to decarbonize already exists and this sector is critical to decarbonizing other sectors, such as transportation and buildings.

Current Status

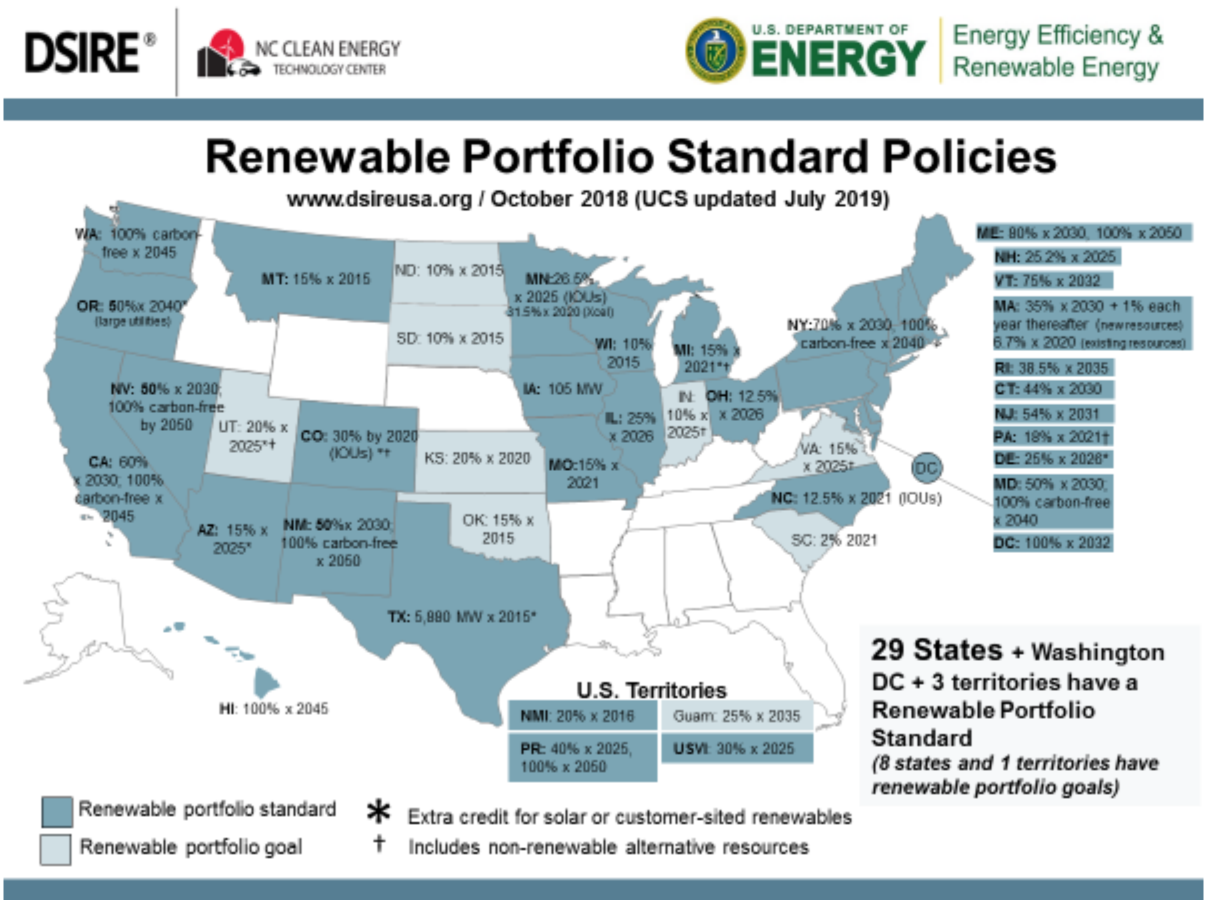
Arizona was an early leader when it adopted the Renewable Energy Standard and Tariff (REST), but we have since fallen behind many of our neighboring states. All of Arizona's large utilities have announced plans to increase their clean energy resources and/or reduce their carbon emissions. However, Arizona's only requirement is 15% renewable energy by 2025. An updated REST should at least match voluntary commitments made by utilities.

You can view the announcements from Arizona utilities here:

Salt River Project (SRP): https://www.srpnet.com/environment/sustainability/2035-goals.aspx;

Tucson Electric Power (TEP): https://www.tep.com/news/tep-plans-clean-energy-expansion-carbon-reduction/; and

Arizona Public Service (APS): https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/EnergyResources/CleanEnergyCommittment.ashx?la=en&hash=EC0606653A170A6A83A716703CD62B44.



Policy Opportunities

The Arizona Corporation Commission has been considering an update to the REST for two years. ACC Staff has proposed a new rule that would require 100% clean energy by 2050 and 50% renewable energy by 2035. Stakeholders and ACC Commissioners have also put forward proposals. It is important that a new rule be adopted. An improved REST should focus on carbon reductions, as opposed to specific technologies; have interim metrics to spur reduced emissions sooner; and must include a tracking mechanism. The soonest the rule update could be completed is 2021. The docket number is RU-00000A-18-0284 and all documents can be found here: https://edocket.azcc.gov/Docket/DocketDetailSearch?docketId=21658#docket-detail-container2

Prepared by: Autumn T. Johnson, Energy Policy Analyst, Western Resource Advocates

Phone: 623.439.2781; Email: autumn.johnson@westernresources.org

Western Interconnect Clean Energy Study

GenX Modeling Results | March 10-11, 2020

Jesse D. Jenkins, PhD
DeSolve, LLC

Greg Schivley, PhD
Carbon Impact Consulting

Commissioned by:

WESTERN RESOURCE ADVOCATES

CLEAN AIR TASK FORCE

Model Setup and Assumptions

The GenX Model

- Highly configurable
- Detailed operating constraints (unit commitment, etc.)
- Hourly resolution
- Transmission losses & reinforcements
- Distribution losses, reinforcements & “non-wires” alternatives
- Distributed energy resources & flexible demand

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Enhanced Decision Support for a Changing Electricity Landscape:

The GenX Configurable Electricity Resource Capacity Expansion Model

An MIT Energy Initiative Working Paper
Revision 1.0
November 27, 2017

Jesse D. Jenkins*†

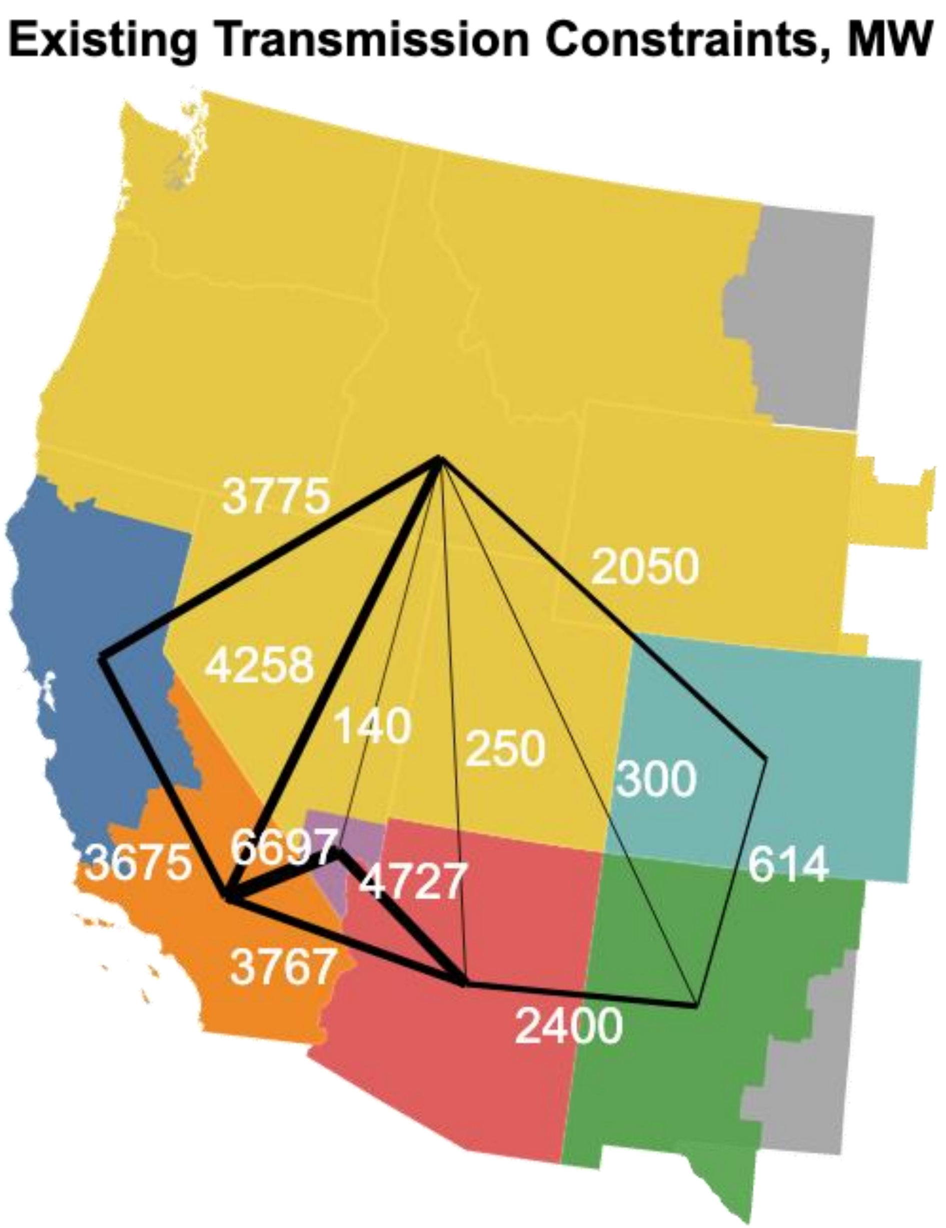
Nestor A. Sepulveda*‡

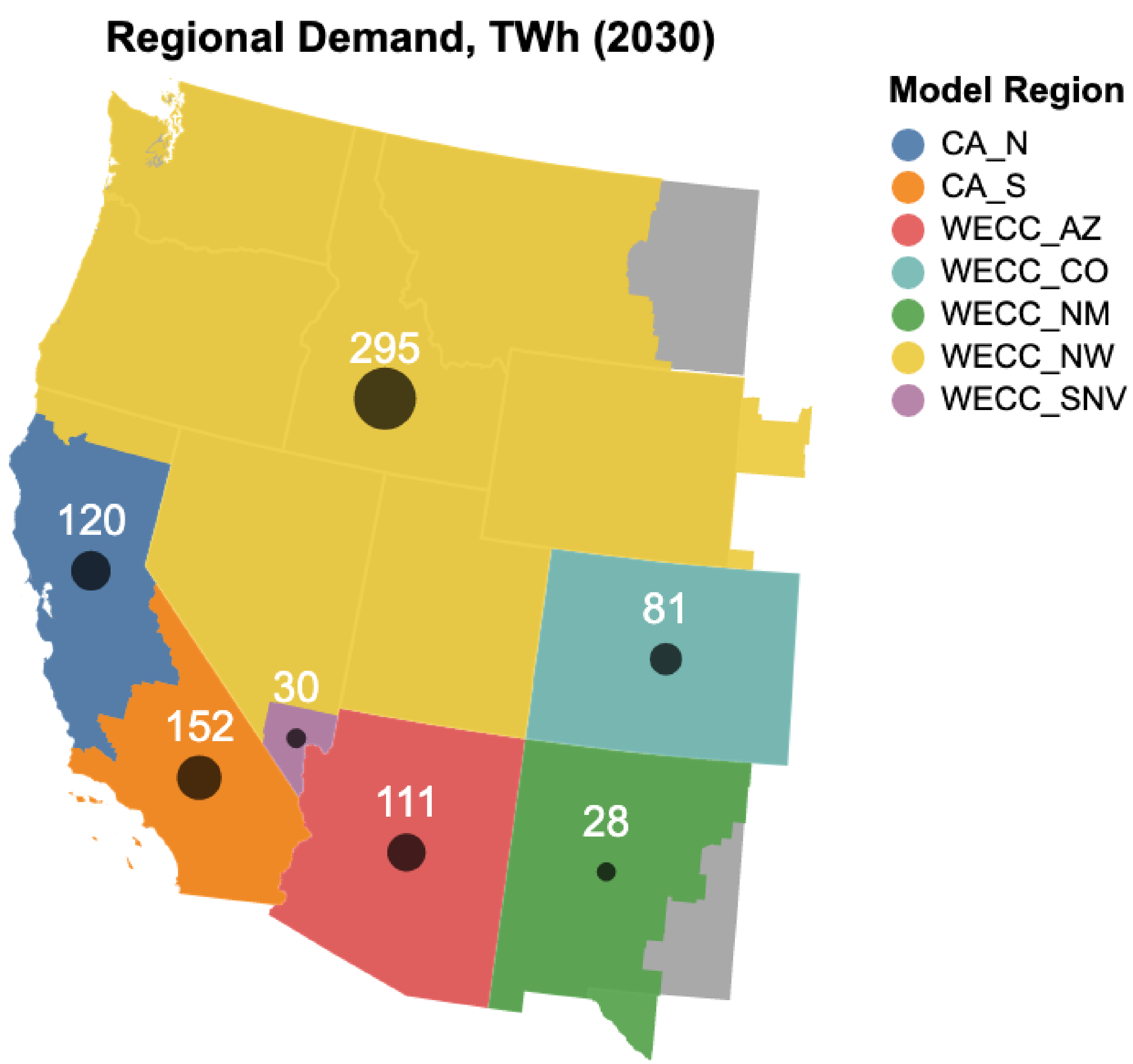
http://bit.ly/GenXModel

*These authors contributed equally to this work

Powered by: julia + JUMP

Western Interconnection (WECC) 7-zone GenX Model





Baseline scenario inputs and assumptions

Input	Description
Planning periods	No-foresight periods of 2020-2030 and 2031-2045. Technology costs based on average of costs over all years in period.
RPS	Wind, PV, small hydro, geothermal, biomass. (Conventional hydro qualifies for 100% RPS case in 2045)
WRA CES	Technology neutral, credit based on emissions rate. Gas CC is ~0.6 credits/MWh, CT is ~0.4 credits/MWh. 0.96 credits for NGCC w/CCS @ 90% capture rate. Zero-emission technologies (including renewables, hydro, nuclear, NGCC w/CCS @ 100% capture rate) are 1 credit/MWh.
Tech CES	1 credit per MWh for qualifying technologies: renewables (including hydro) plus nuclear and NGCC w/CCS (both 90% and 100% get 1 credit).
Load growth	2011-2019 growth based on historical rates from EIA. Future rates based on EIA AEO reference for regions in WECC. AZ base growth rate of 2%, which is higher than Southwest value of 1.1%.
Transmission expansion	Add up to 100% existing capacity in each planning period.
EV growth and charging	Scale hourly profiles from Evolved Energy Research to match 1.3/2.7 million MWh (2030/2045) AZ load from MJ Bradley. Apply ratio of AZ load/EV load to other regions. 80% of charging in each hour can be delayed up to 5 hours.

Examine range of policy scenarios and sensitivity of model inputs (2030/2045)

Case Description	CES	RPS
WRA CES with RPS	~81% in 2030*/100% in 2045	50%
WRA CES	~81% in 2030*/100% in 2045	None
Tech CES + RPS	80% in 2030/100% in 2045	50%
Tech CES	80% in 2030/100% in 2045	None
RPS only	None	50% in 2030/100% in 2045

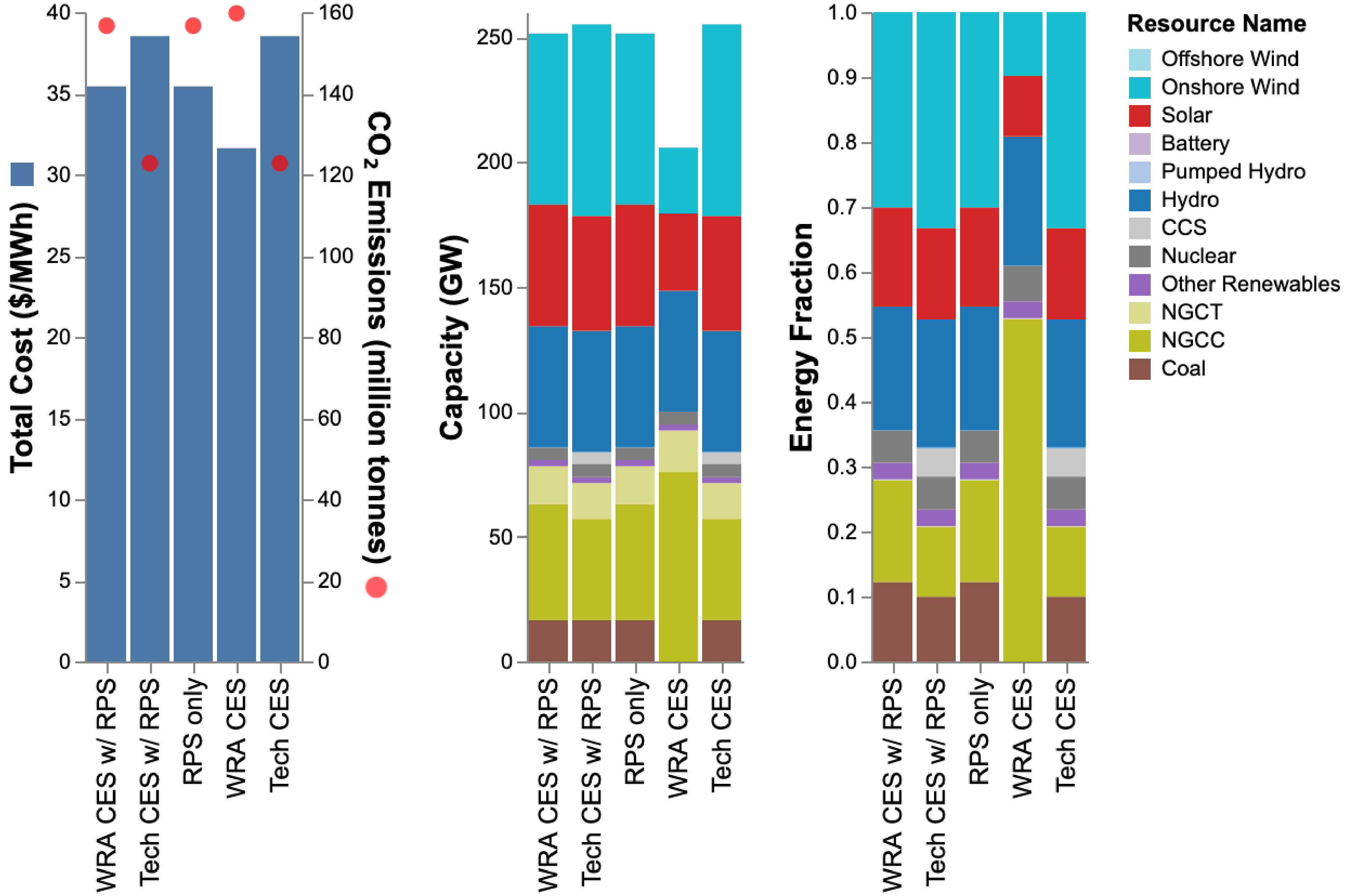
* Equal to WECC emissions 40% below 2016 levels. Exact requirement varies based on total load.

Examine range of policy scenarios and sensitivity of model inputs (2030/2045)

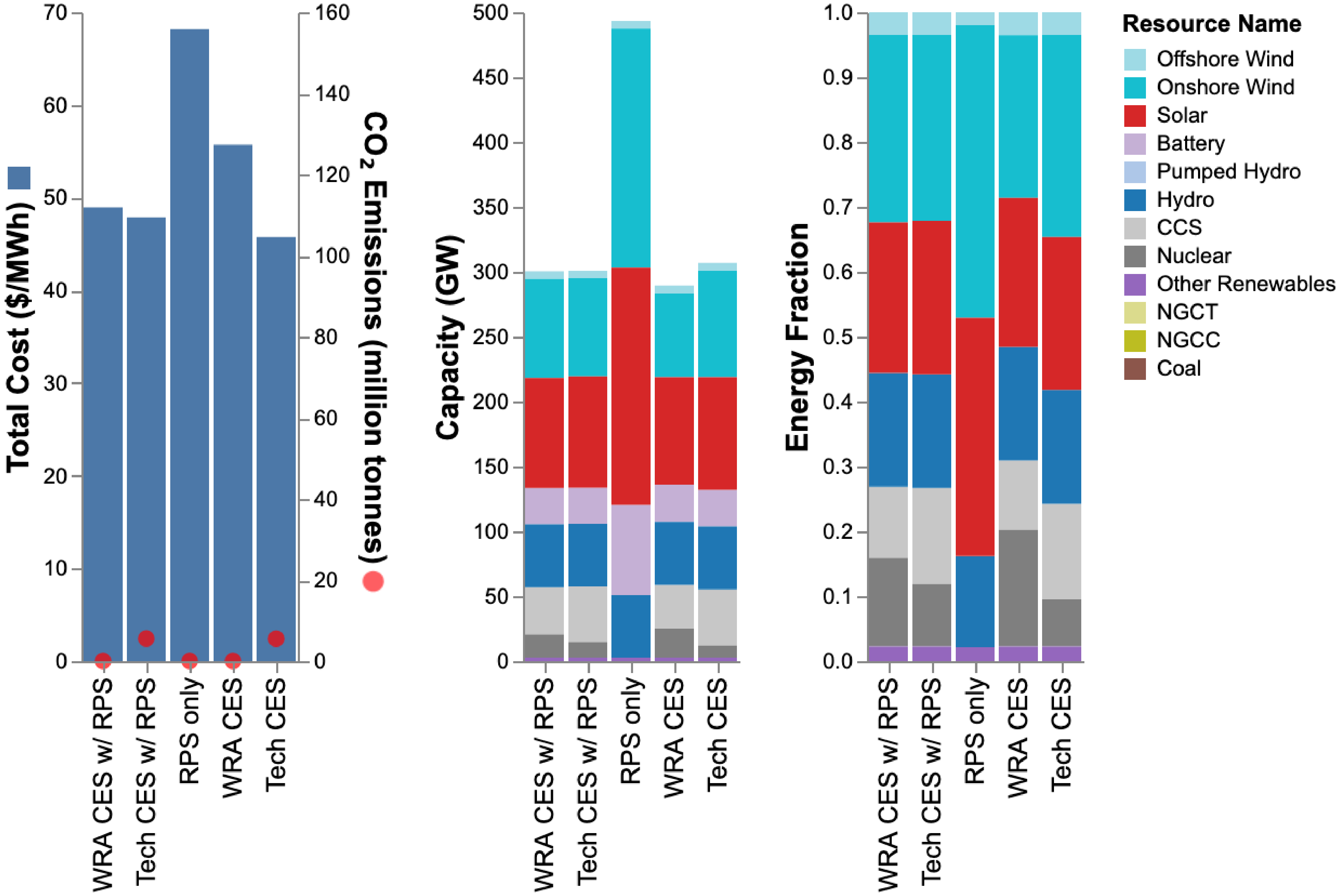
Case Description	Load Growth	Costs	Transmission Build	EV Load
Slow AZ load growth	Default EIA SW rate of 1.1% for AZ before EV load	Baseline	Baseline (maximum 100% expand per period)	Moderate growth (~9.5% VMT by 2045)
Half WECC load growth	Half of default EIA rates (0.15-0.55%) before EV load	Baseline	Baseline	Moderate growth
Limit transmission	2% rate in AZ	Baseline	Maximum 25% of each existing line in a period	Moderate growth
High EV penetration	2% rate in AZ	Baseline	Baseline	High growth (~67% VMT by 2045)
Low cost nuclear	2% rate in AZ	Low nuclear capex	Baseline	Moderate growth
Low gas prices	2% rate in AZ	AEO high resource scenario gas prices	Baseline	Moderate growth
Low cost CCS	2% rate in AZ	Low CCS capex	Baseline	Moderate growth
High cost CCS	2% rate in AZ	High CCS capex	Baseline	Moderate growth
Low cost renewables	2% rate in AZ	Low wind/PV/battery capex	Baseline	Moderate growth
*Other cases	Phase out all coal by 2030, phase out coal + no new gas, no new gas			

Results - WECC

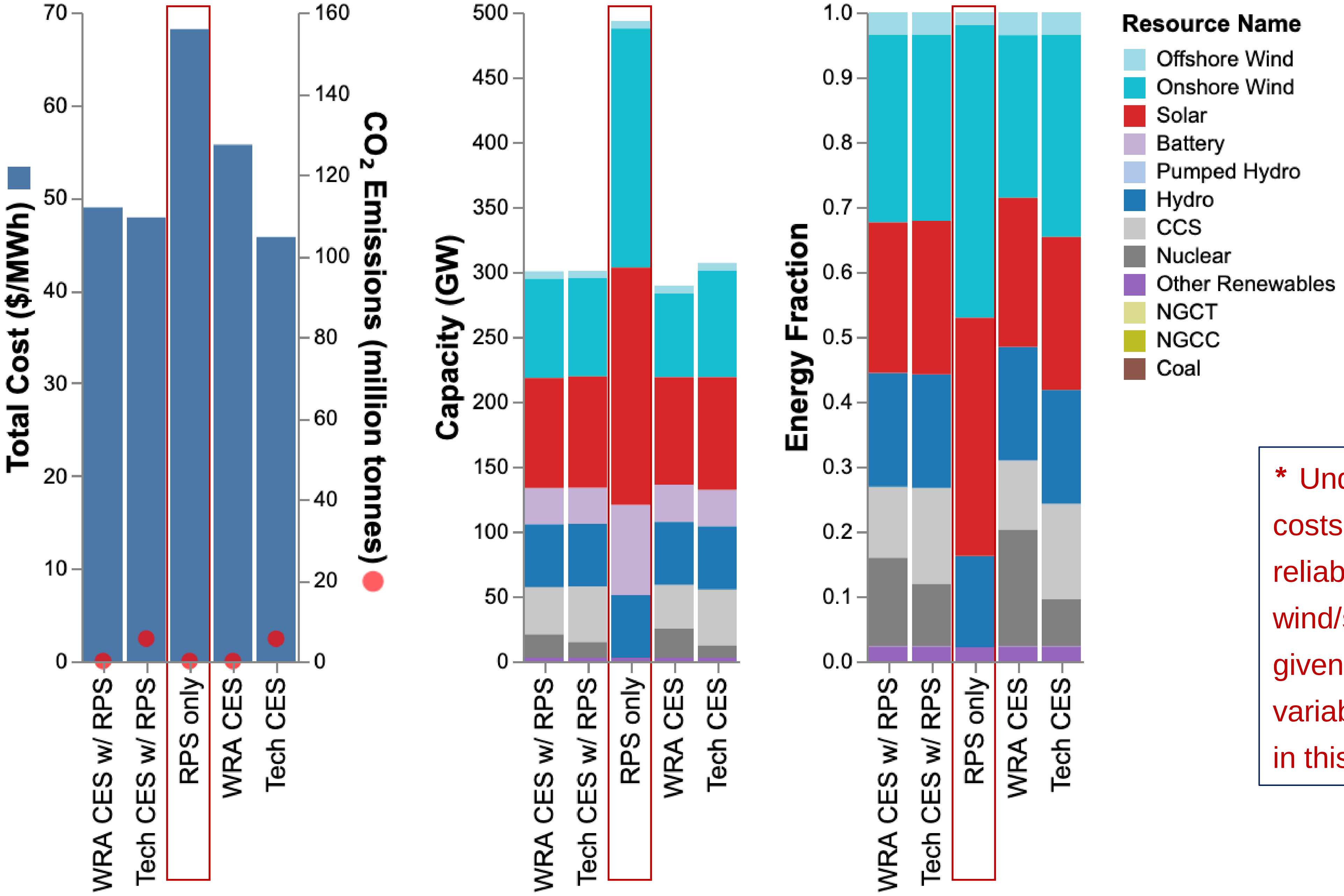
Policies all achieve >40% CO_2 reduction (below 2016) by 2030 at modest cost



CES delivers 100% carbon-free electricity by 2045 at cost under $55/MWh



Excluding firm zero carbon sources (100% RPS) raises prices 22-39% in 2045*

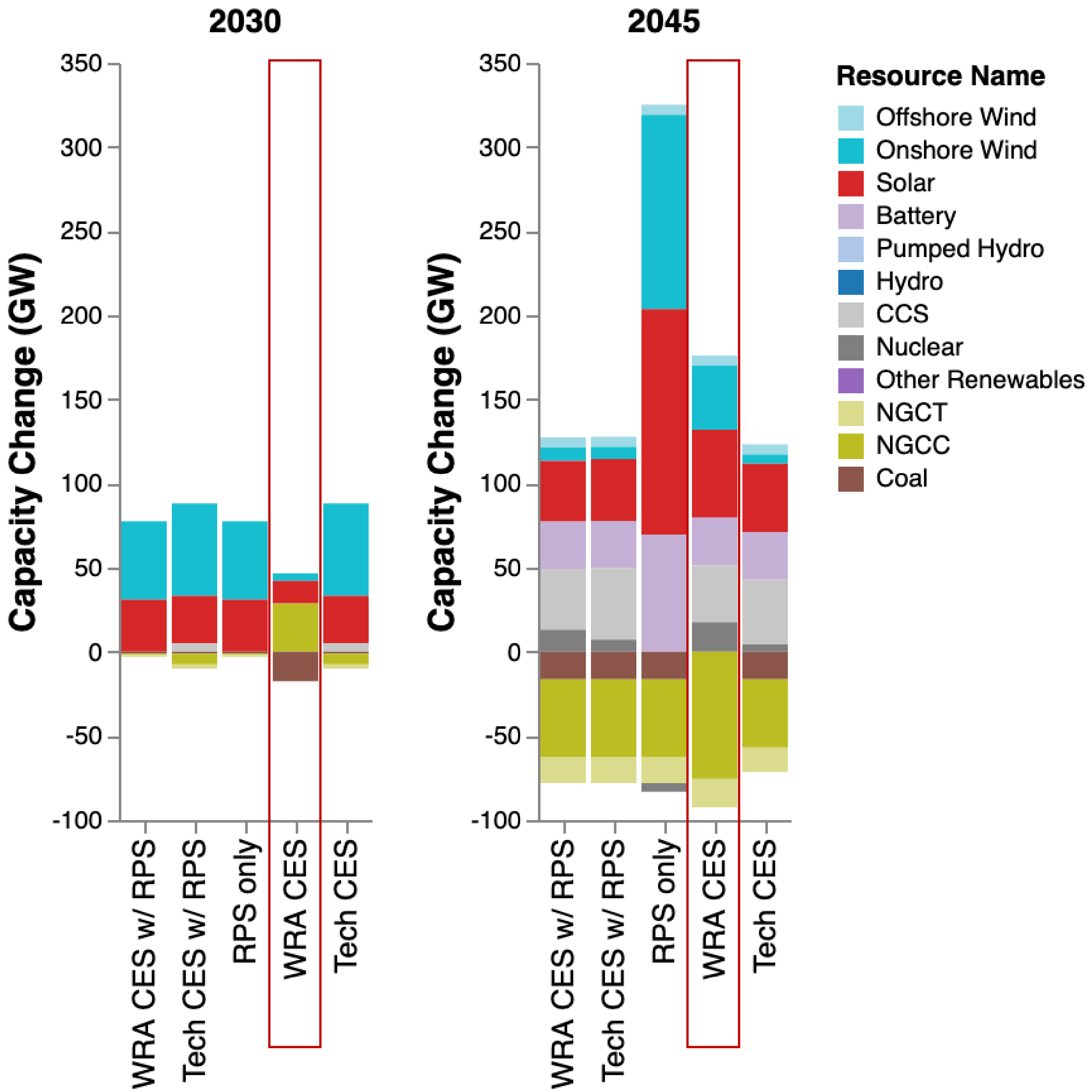


* Under-estimate of total costs required to meet reliability needs in bad wind/solar/hydro years given inter-annual variability not considered in this study.

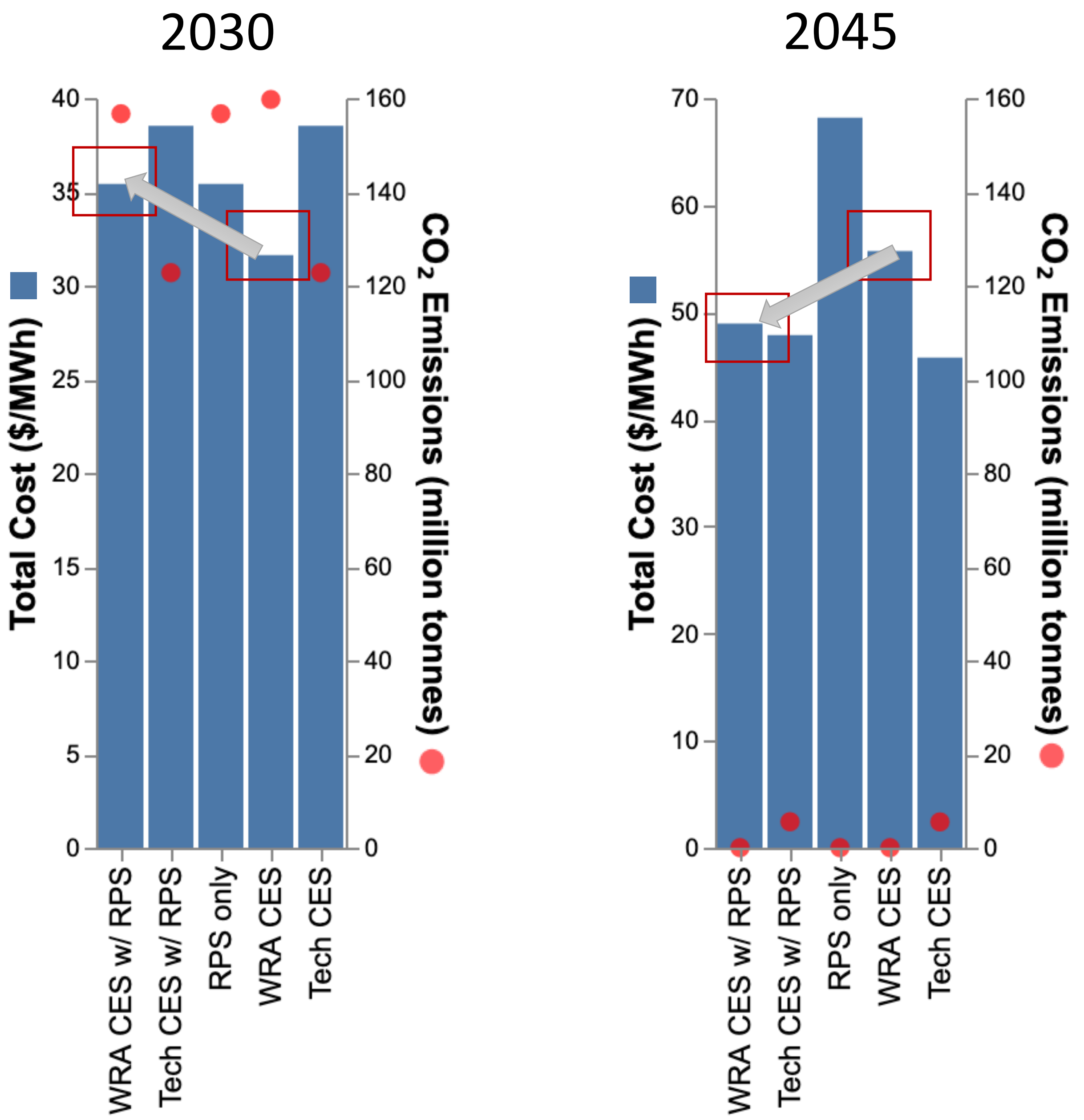
WRA CES without RPS replaces coal w/new gas, builds more renewables in 2045

Without layering a 50% RPS and the WRA CES, coal can be replaced by natural gas when it receives partial CES credit. The gas is lower-cost in 2030 even with a 15-year financial asset life.

The renewable resources needed to meet zero-carbon goals are then built in the 2031-2045 period.



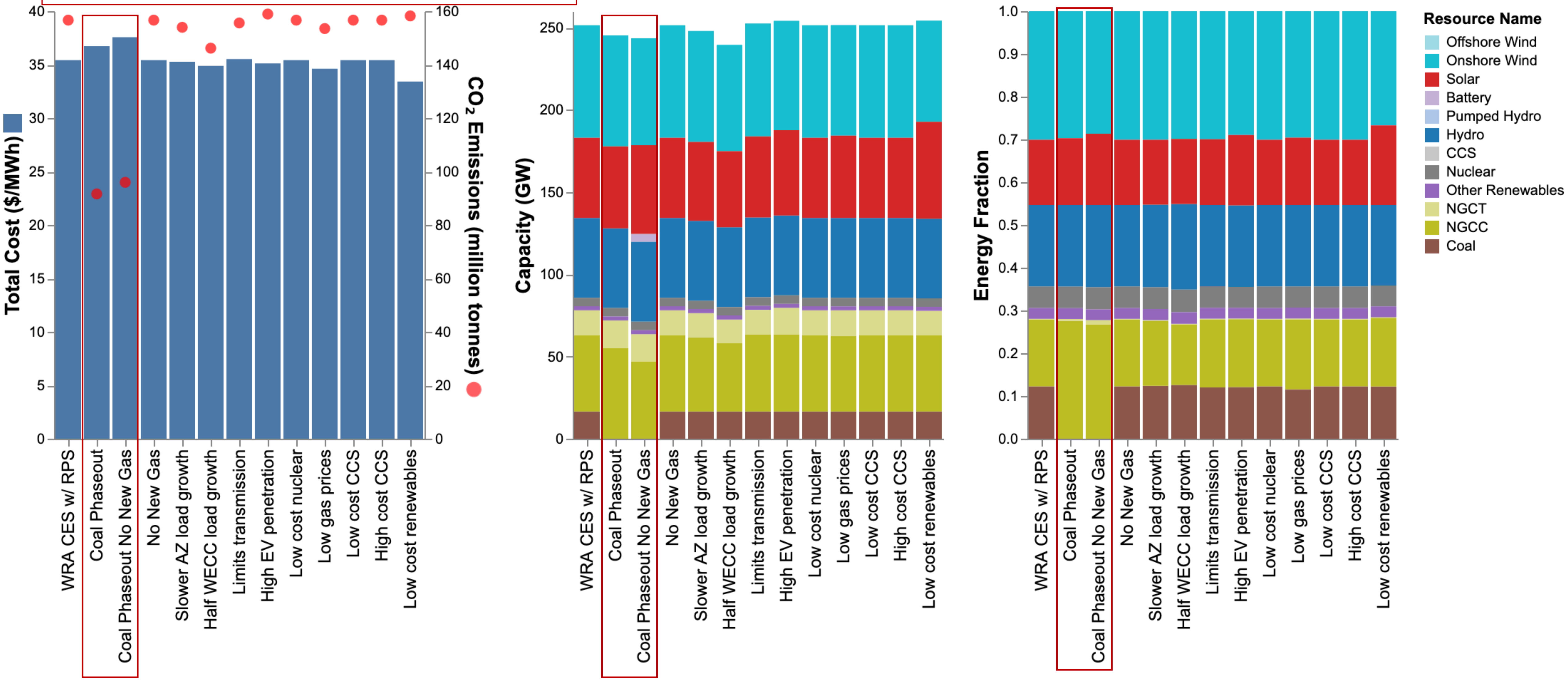
The RPS increases WRA CES costs slightly in 2030 but lowers costs in 2045



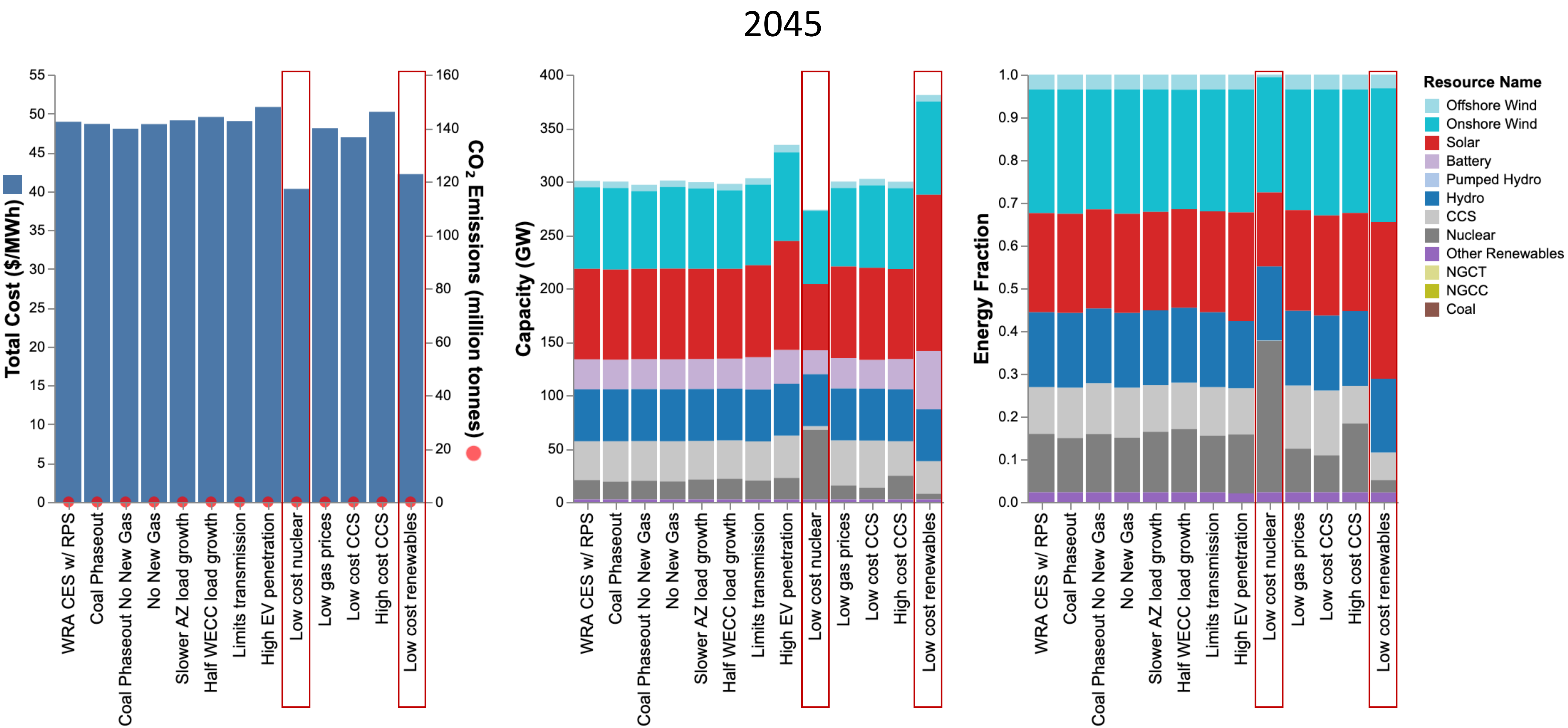
System costs are similar across sensitivities in 2030*

*CO_2 emissions 62-66% below 2016 in coal phase-out cases vs ~40% in other cases at modest cost increase

2030

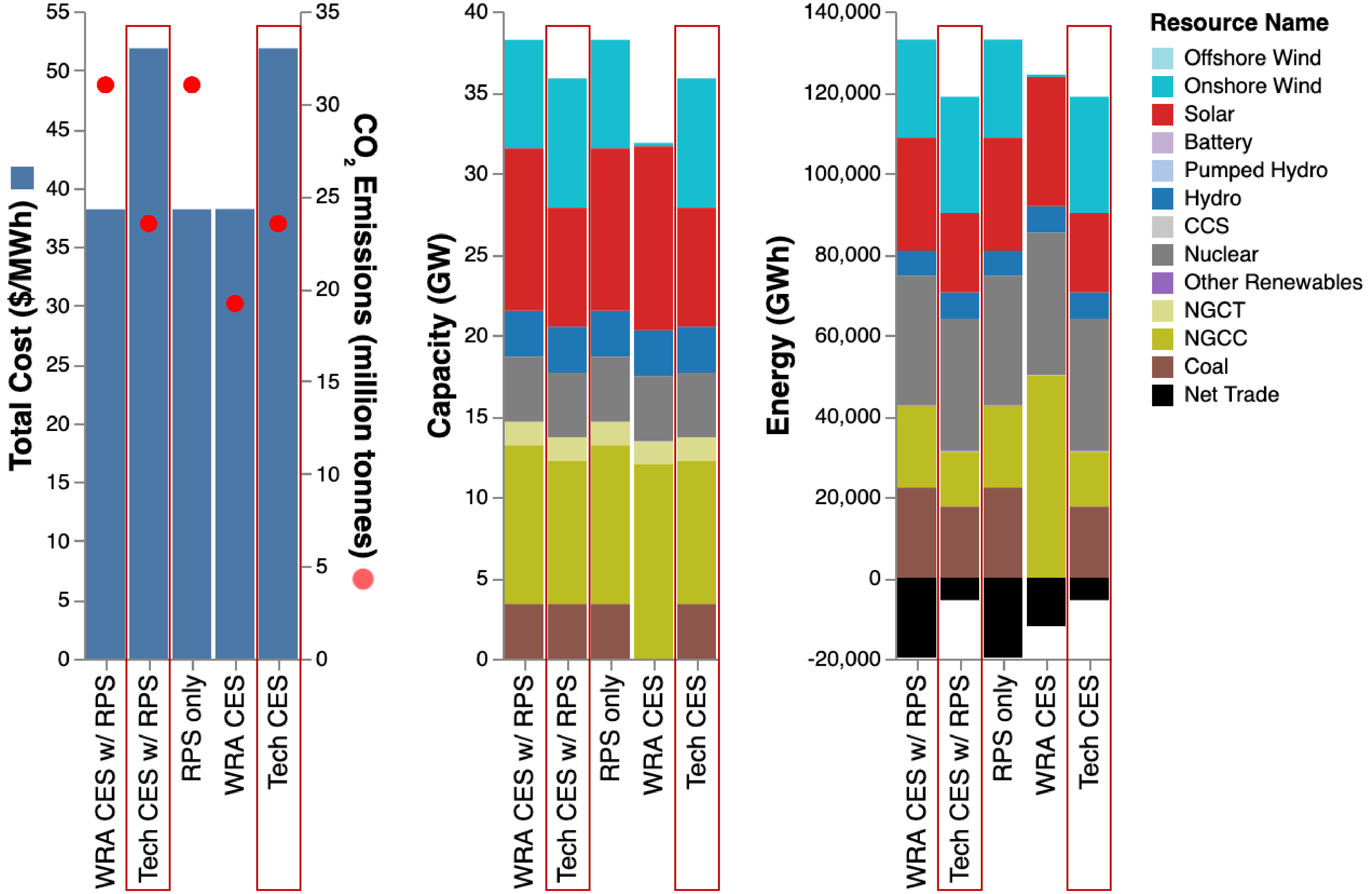


Low-cost nuclear or low-cost renewables lower system costs in 2045



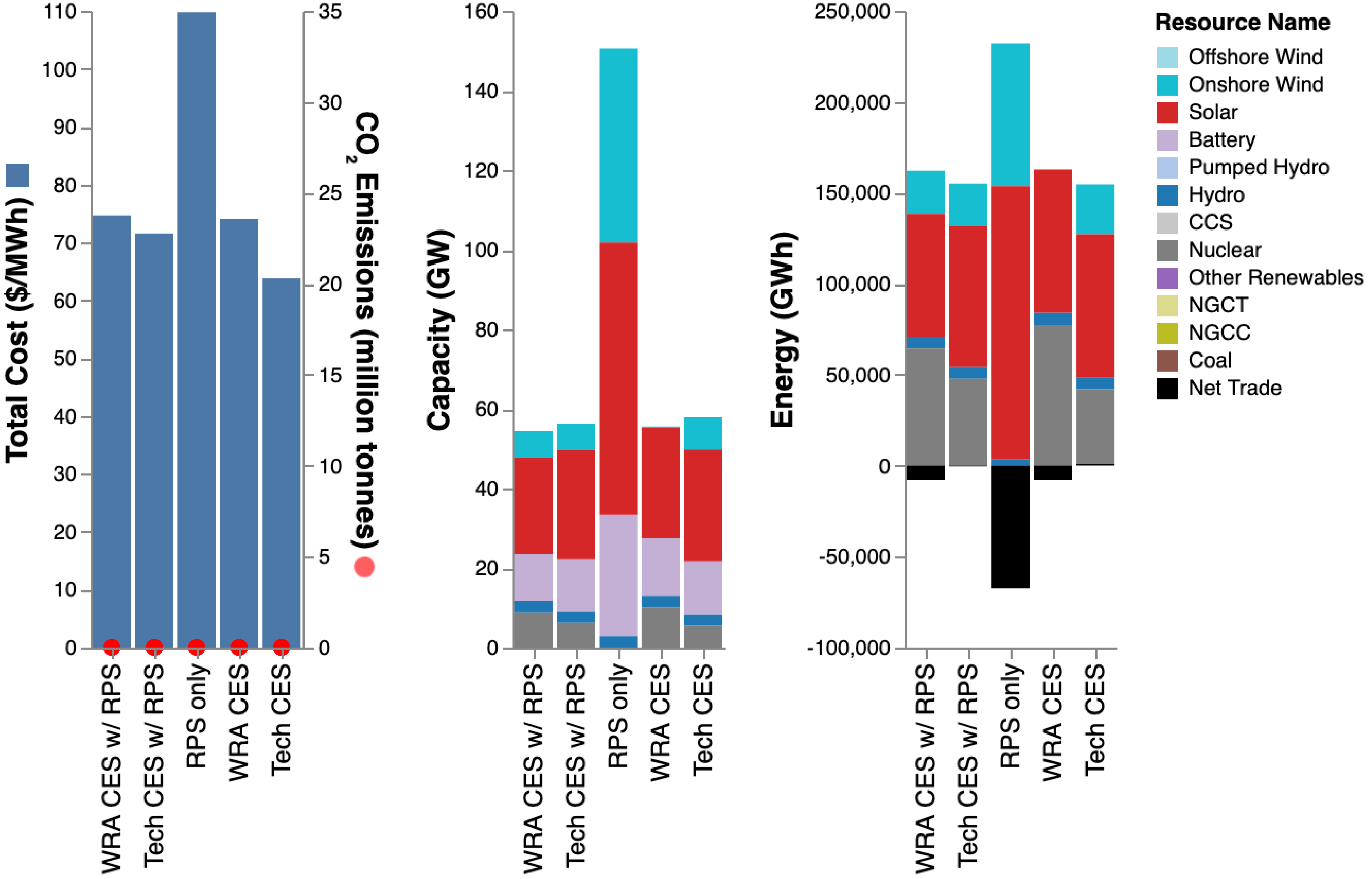
Results - Arizona

Tech CES raises AZ costs in 2030, reduces net power exports

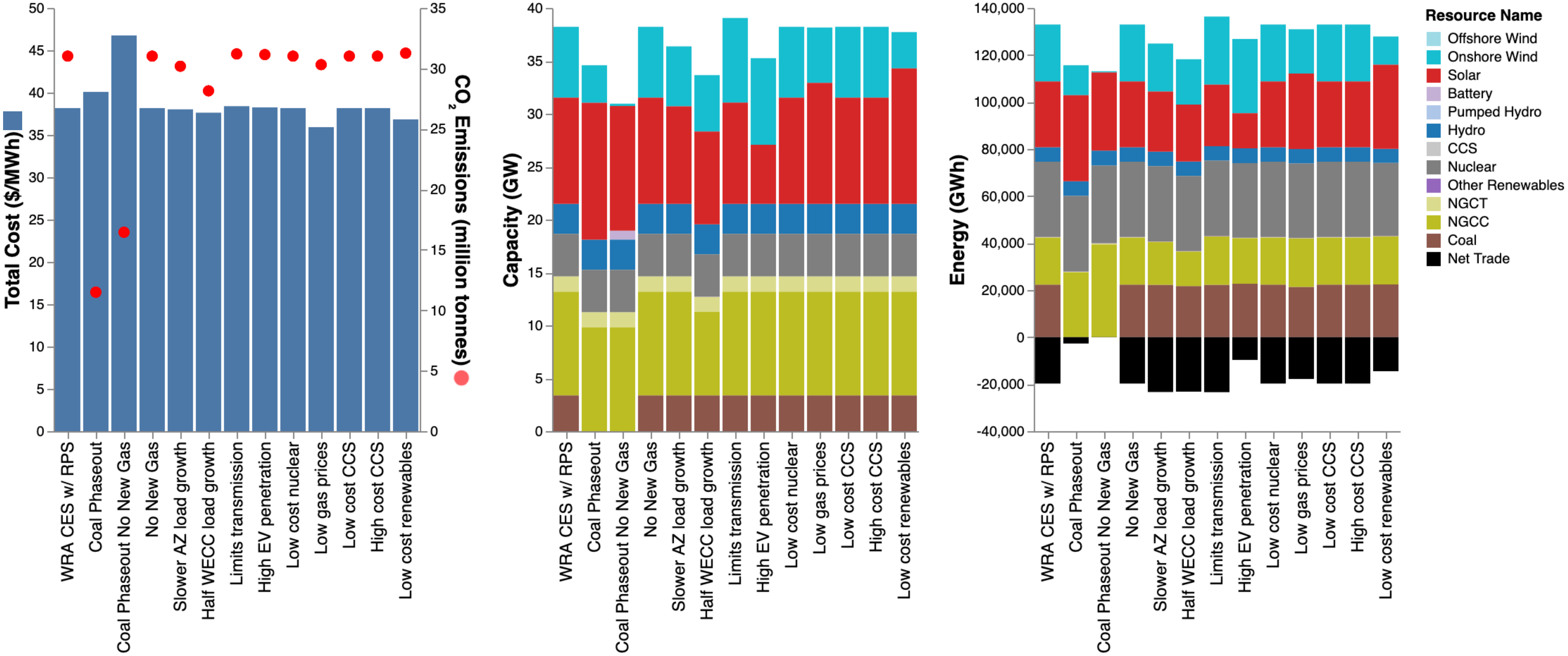


Arizona costs in 2045 are much higher with RPS-only policy

***Important:** AZ results are in the context of a least-cost optimization of the entire WECC. The model does not try to achieve the least-cost outcome for AZ. Many solutions may exist that could change the AZ-specific resource mix and costs with very small increases in total WECC-wide cost. Average WECC costs are more indicative of the average cost of AZ supply that could be achieved through planning and long-term contracting.

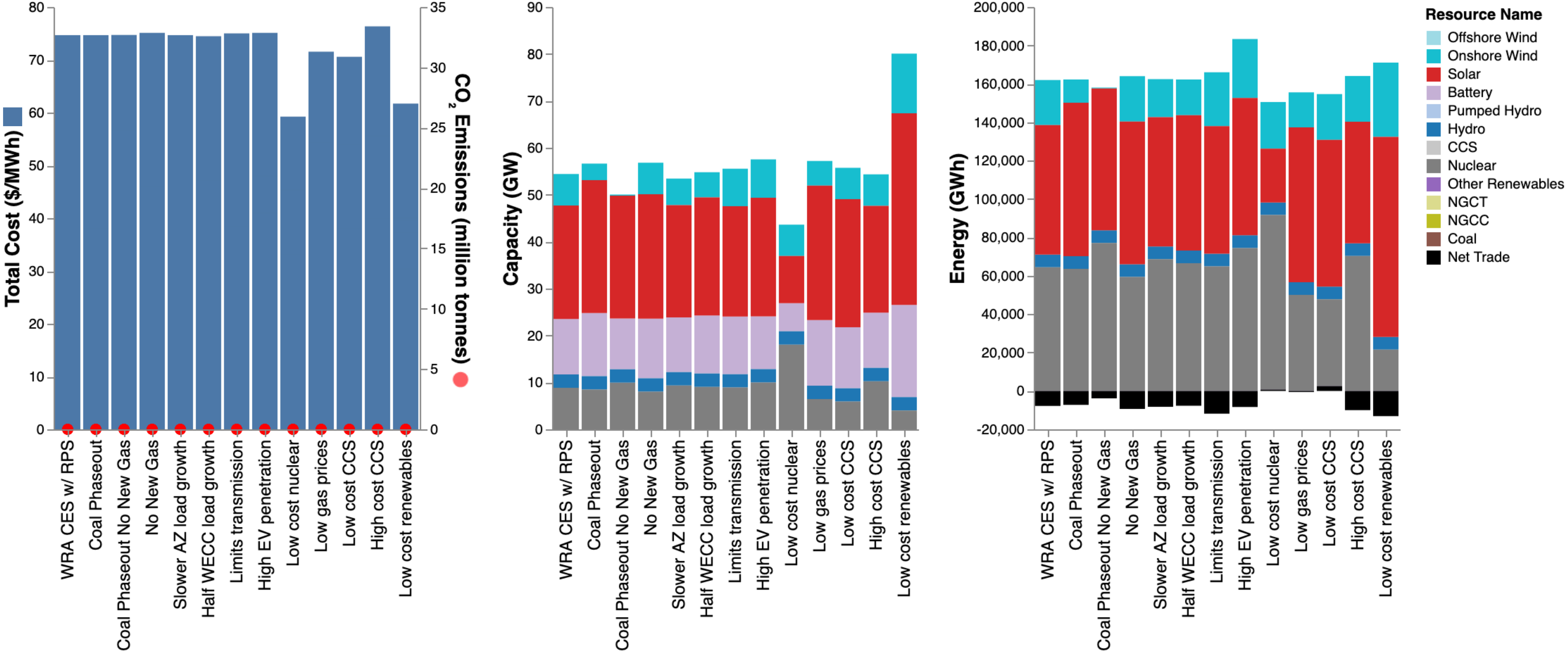


AZ costs are similar across sensitivities in 2030, lowest emissions with coal phaseout



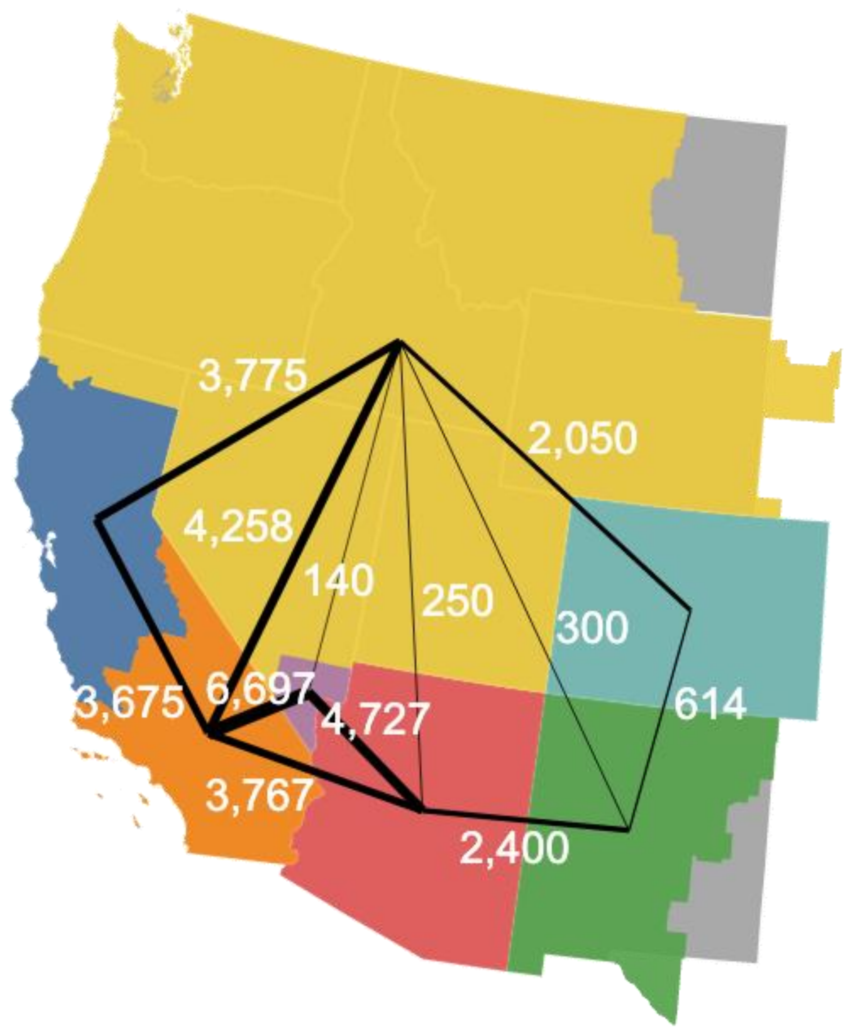
Low-cost nuclear or low-cost renewables lower system costs in 2045*

*AZ specific costs are calculated in a WECC-wide optimization. Many other options could lead to lower costs in AZ.

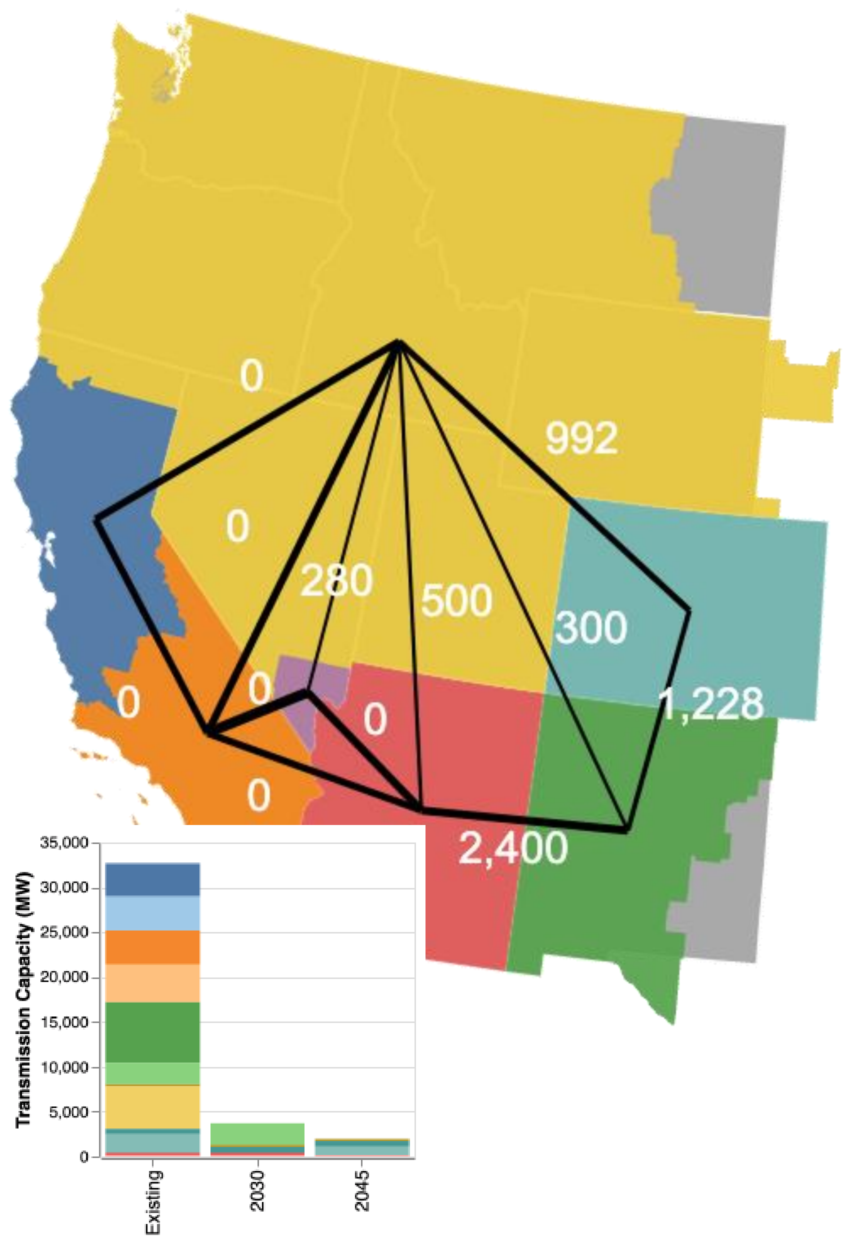


Clean firm resources reduces dependence on new transmission for 2045 goals

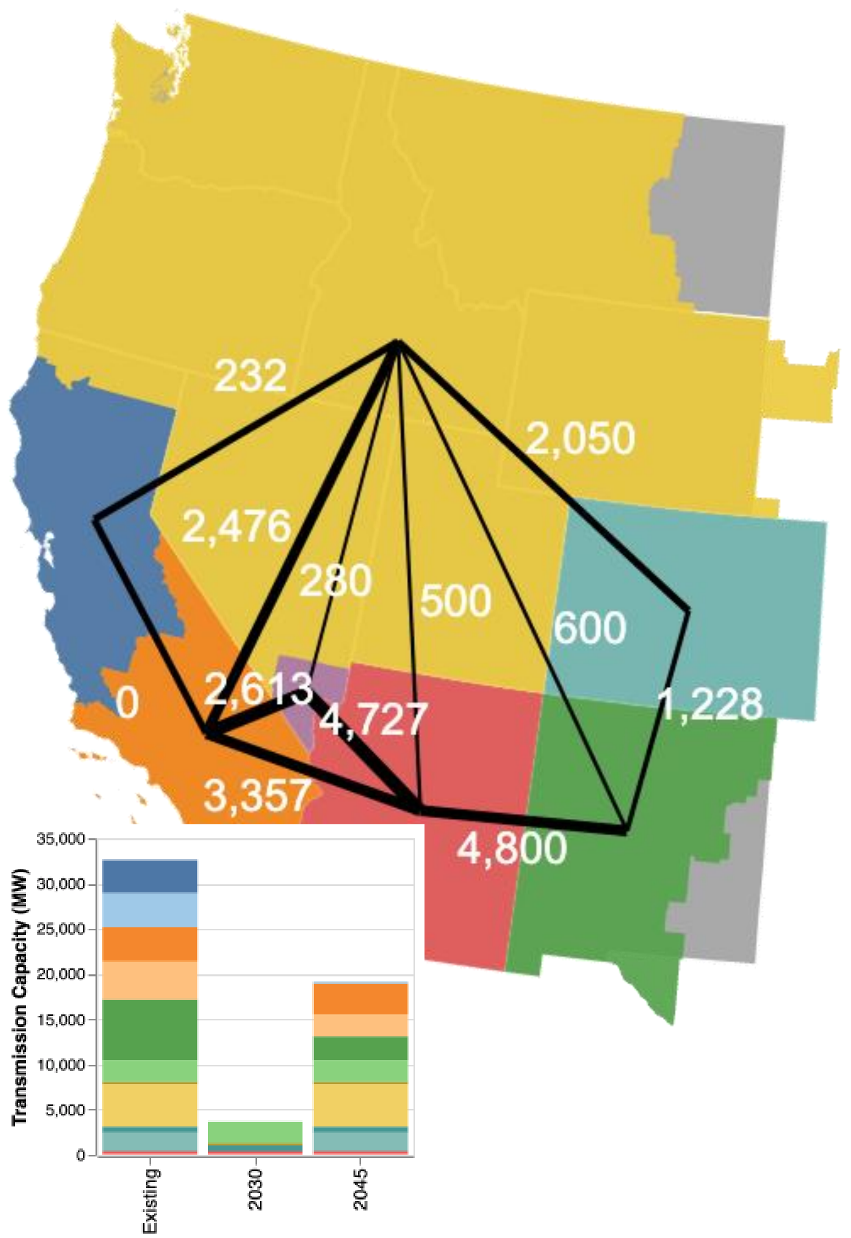
Existing Transmission Constraints, MW



WRA CES w/ RPS



RPS only



Key Conclusions For Western Interconnect

1. WECC can achieve a zero-carbon grid by 2045 at a cost of $40-55/MWh, even with increased demand due to electrification, provided that all zero carbon resources can compete to provide power.
2. Costs are 20% lower if renewable or nuclear costs are in the lower range of estimates.
3. Coal phaseout drives deep emission cuts by 2030 at a cost of $2-3/MWh.
4. Under all scenarios, Arizona builds at least 30 GW of new clean generating capacity, roughly the amount in service today.
5. Retaining the option for firm zero-carbon generating capacity (e.g. CES construct) avoids a 50% generation cost increase realized in scenarios that exclude such capacity (e.g. RPS only).

1. Now is the time to increase the REST.
2. The Joint Stakeholder proposed rules - a long-term, technology-neutral CES with an RPS in the near term - is the preferred policy.
3. Imposing an RPS in 2030 drives near-term investments in renewable energy, at modest cost increases.
4. A CES will support further technological and market developments that will avoid a generation cost increase of 50%, reduce in-state generating capacity requirements by more than 60%, and reduce required interstate high voltage transmission line capacity by 85%.

WESTERN RESOURCE ADVOCATES

CLEAN AIR TASK FORCE

DECARBONIZING THE ELECTRICITY SECTOR & BEYOND

A REPORT FROM THE 2019 ASPEN WINTER ENERGY ROUNDTABLE

Roger Ballentine & Jim Connaughton, Co-Chairs

Dave Grossman, Rapporteur

THE ASPEN INSTITUTE ENERGY & ENVIRONMENT PROGRAM

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The latest Intergovernmental Panel on Climate Change (IPCC) report has intensified the focus on measures to achieve deep decarbonization. For the United States, most experts say that, if the aim is to be on a 1.5°C pathway, the United States must achieve a net-zero carbon profile economy-wide by around mid-century, going negative thereafter. There are five basic elements of achieving deep decarbonization of the energy system: (1) employ energy efficiency to the maximum degree; (2) decarbonize the electricity supply; (3) electrify other sectors as much as possible, including heat, transportation, and industrial processes; (4) use zero-carbon fuels for the areas that cannot be effectively electrified; and (5) use carbon capture, utilization, and storage (CCUS) and carbon dioxide removal (CDR) for areas where fossil fuels are still needed and for achieving negative emissions.

Clean energy has been growing in the United States and around the world, but to achieve deep decarbonization, much, much more is needed. While the shares of different fuels in the U.S. and global energy mix have changed dramatically over the past couple of centuries and even the past few decades, the share of global energy supplied by clean energy over the last decade has remained flat, as clean energy growth is only just keeping up with total energy growth, including new fossil fuel generation growth. Furthermore, from a climate perspective, what matters is not shares but the absolute levels of usage and emissions – and from that vantage point, the changing energy picture has been less a story of transitions than of additions, with any changes in shares swamped by growth in overall energy demand. A true energy transition to achieve deep decarbonization will require not just additions of new incremental capacity but also subtractions of the carbon-intensive parts of the current energy system. This is not yet happening globally, though the United States may be experiencing some transition, with flattening demand from energy efficiency, growing use of natural gas, declining coal generation, and a move to lower-carbon sources, including increased deployment of solar (distributed and utility-scale) and a growing role for battery storage (both driven largely by plummeting costs).

The increased attention to deep decarbonization has focused the debate around whether the goal is 100% renewables (mostly solar and wind) or 100% zero-carbon. Studies looking at deep decarbonization scenarios for the grid have generally found that the availability of some kind of firm, zero-carbon power (e.g., nuclear, hydro, geothermal, biomass, fossil with CCUS, hydrogen, long-duration storage) reduces the costs and risks of decarbonization, particularly as the penetration of variable renewables increases. This is largely because of the variability – particularly the seasonal variability – of wind and solar. While the country is still at such low levels of renewables penetration that the debate about what to do when penetrations get really high can seem somewhat academic, policies adopted now could either open or foreclose technological decarbonization options. The likely need for zero-carbon dispatchable resources in a decade or two suggests that it is better to keep options open. Still, large corporate buyers, who have been among the biggest drivers of clean energy in recent years, have focused their purchasing almost exclusively on renewables. This is partly because wind and solar are easier in terms of public opinion, the risks of NGO criticism, and accounting, but it is also partly due to the fact that most companies are seeking only to match their amount of energy usage, not to actually power their facilities 24/7 with electrons from zero-carbon power sources.

Because of the changing expectations of customers (big and small), new technologies, and overarching objectives such as decarbonization, states are beginning to rethink what the electricity distribution grid looks like and how to plan it. Growing numbers of distributed energy resources (DERs) are changing the needs and capabilities of the grid, so some states and regulators are starting to look at distribution grid planning processes that encourage DERs where they are helpful to the overall system and that compensate DERs for the value they provide. There are technological opportunities behind, at, and in front of the meter, including automated interoperable home devices, smart meters, smart inverters, and high-resolution sensors. Utility investments in DERs and grid modernization, however, are hindered by antiquated cost-effectiveness tests and accounting rules, such as ones that favor capex over opex and thus limit utilities' incentives to invest in software and cloud services to utilize the data being collected by smart technologies. Some critics have also argued that only the rich benefit from DERs while the poor subsidize them, but community solar is one way of democratizing access to clean energy. Technologies such as blockchain can allow people to use their DERs to provide peer-to-peer energy transactions, though there are some policy, technology, and cost barriers to that at the moment.

In the U.S. wholesale electricity system, competitive markets have fostered innovation, lowered prices, and facilitated renewables deployment. Technological advancements in storage, demand response, and energy efficiency, however, are reducing the need for instantaneous matching of supply and demand and for constructs such as mandatory reserve margins and optimal capacity mixes. The U.S. Federal Energy Regulatory Commission (FERC) plays an important role in removing barriers to the participation of storage in wholesale markets, streamlining processes to better integrate renewables, and breaking down barriers to entry for aggregated DERs, but FERC is facing challenges regarding how to value the externalities (e.g., carbon, resilience) of various types of power sources. As those externalities go unvalued at the federal level, states are increasingly stepping in with out-of-market supports for local sources of generation. It is a question of perspective whether these supports are distorting the market or filling gaps in it – and whether imperfect markets or imperfect regulations are better for meeting the range of societal goals.

While much of the decarbonization focus tends to be on electricity, transportation has surpassed it as the largest contributor of GHG emissions in the United States. With respect to light-duty vehicles, a lot of decarbonization efforts are focused on battery electric vehicles (EVs), sales of which are growing rapidly. Some major manufacturers have announced plans to convert their fleets from internal combustion engines to electric. Other key accelerants for EV adoption could include the deployment of charging infrastructure, policy incentives, the ability to monetize the grid benefits provided by EVs, and the rise of shareable autonomous mobility-as-a-service. Potential headwinds to EV adoption, meanwhile, include the availability of materials for batteries, restrictions on direct sales to consumers, and transportation infrastructure that was not designed with a variety of vehicle types in mind. With regard to medium- and heavy-duty vehicles, there are many technological and operational opportunities for improving truck efficiencies, and batteries and hydrogen fuel cells could be options for decarbonizing trucks' energy needs. Air travel is where transportation fuel use is growing fastest, and there are opportunities for both incremental and transformational improvements in airplane efficiency, including better engines, design modifications to wings and propulsion systems, and reducing weight by using more carbon-fiber in frames. Finding low- and zero-carbon fuels for aviation will also be important, and batteries (for short-haul and potentially medium-haul trips), liquid hydrogen, and biofuels are all possibilities.

Beyond electricity and transportation, industry accounts for about one-third of global emissions, though it accounts for a far smaller fraction of global decarbonization effort. There are potential decarbonization solutions that cut across industrial sectors, such as more efficient motors, industrial CCUS, electrification, and zero-carbon hydrogen. Demand for materials made through low-carbon production could be advanced with protected markets created by government and corporate procurement programs. There are also demand-side ways to lower industrial emissions by reducing energy needs (e.g., through use of more efficient equipment and processes) and by necessitating less materials production (e.g., through business models that deliver services instead of stuff, recycling of construction and demolition waste, and substituting less carbon-intensive materials). The epicenter of efforts to reduce industrial emissions has to be the Gulf Coast, where Texas and Louisiana account for the vast majority of U.S. industrial GHG emissions and where billions of dollars are being spent on new petrochemical expansions and refining.

Across sectors, there will almost certainly still be lots of carbon-based energy for years to come. CCUS technologies will affect the ability of fossil fuels to participate in a deeply decarbonized world, while CDR technologies could prove vital to keeping atmospheric carbon dioxide (CO_2) concentrations within agreed-upon bounds. Carbon capture technologies can help decarbonize both the power and industrial sectors, though the particular capture technologies used (e.g., oxycombustion, solid sorbents) will vary by sector and facility. CDR solutions could include both biological approaches, which store carbon in forests, soils, and ecosystems, and engineered approaches such as direct air capture (DAC), which use chemical processes. DAC systems are currently limited by high costs and access to clean energy, but they might be able to piggyback on existing sources of low-carbon, low-temperature heat (e.g., geothermal and nuclear plants) adequate for regenerating the sorbents used in some DAC systems. To achieve scale, DAC and other CDR technologies will need government incentives, technological advancements, and early CO_2 utilization market opportunities that can increase near-term deployment and allow the technologies to move along the learning and cost-reduction curves. These utilization opportunities could include using captured CO_2 as a feedstock in products (e.g., plastics, nanofibers, fuels), to carbonate beverages, or for other purposes. Captured CO_2 can also be stored underground – the United States has plenty of geological storage capacity – or used for enhanced oil recovery, which involves both utilization and storage and which can produce oil with a much lower carbon footprint than a conventionally produced barrel.

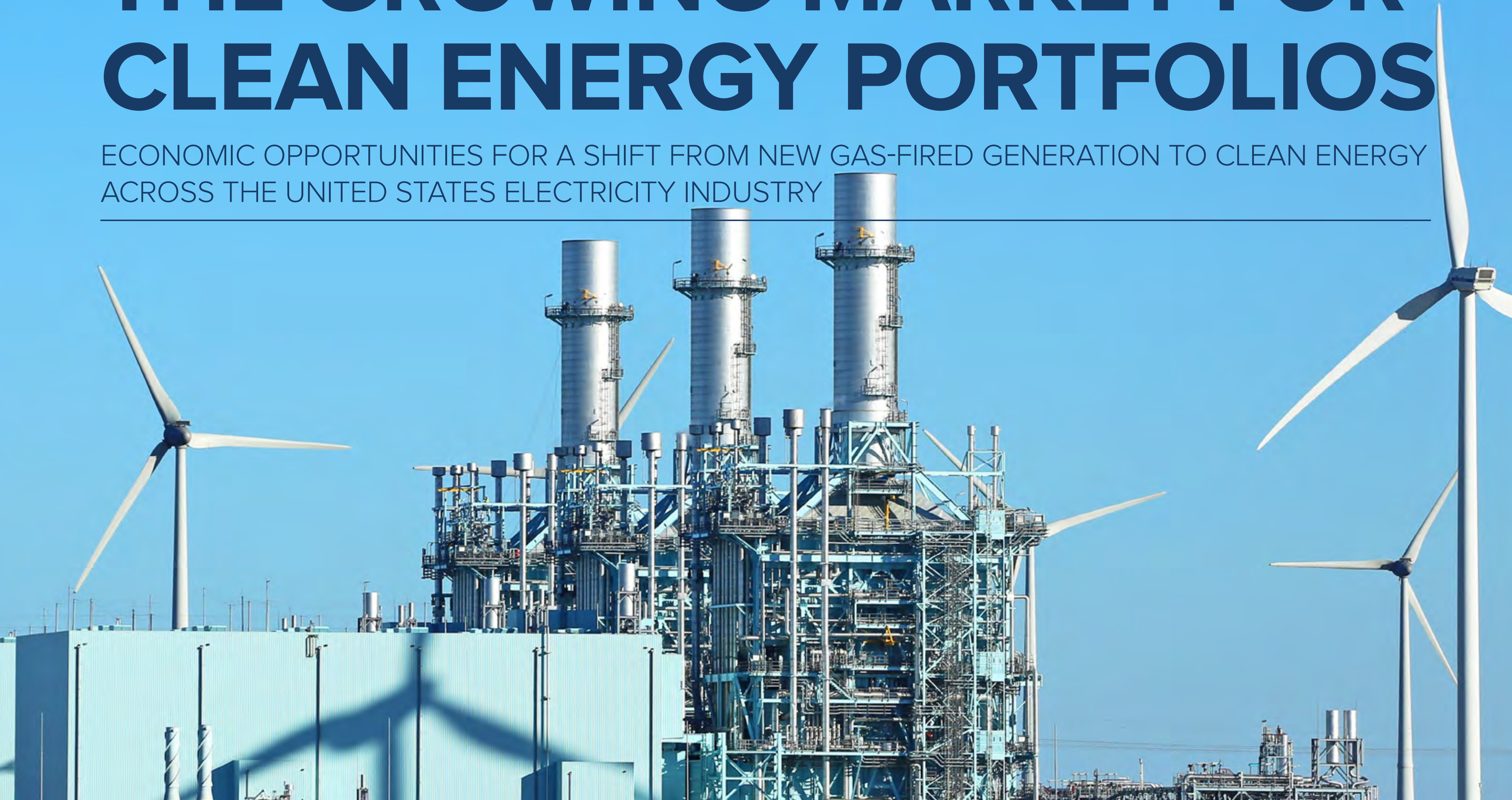
To advance decarbonization of all these sectors and address the many difficult issues that deep decarbonization will raise, there is a need for new, broader, smarter, more significant policy approaches. Broadly speaking, options include policies to internalize the climate externality (e.g., carbon pricing), support innovation (e.g., R&D), provide information (e.g., labeling and certification), account for network- and systems-level effects (e.g., building codes), and deal with geographic spillover issues (e.g., carbon border adjustments). In addition, energy and climate policies have to grapple with the significant human, community, and social values that are at stake, which makes equity a vital part of the climate policy conversation too. Some policy options could have cross-sectoral application, while tailored policies may be needed to address barriers sector by sector. For instance, power sector policies could include energy efficiency standards, renewable or clean energy standards, cap-and-trade, and storage mandates. Policies to electrify other sectors could include performance standards (e.g., vehicle emission and fuel economy standards), building codes, and a shift from energy savings targets to carbon efficiency standards. Government procurement standards and infrastructure policies that can advance CCUS could help with industrial decarbonization. Policies and programs to help farmers increase soil carbon sequestration, lease land for renewables, and gain clarity about the roles of biomass and biogas could help in the agricultural sector. Likely, there will not be one big policy idea that drives decarbonization so much as a mosaic of approaches.

Fortunately, in both state and federal policy circles, climate change is receiving political attention that it has not had for years. At the state level, some clean energy ballot measures succeeded while others failed, some new governors have taken office with much stronger focuses on clean energy and climate change, several states have adopted or are in the process of considering their clean energy goals and the fate of existing coal plants, and some states have advanced efforts explicitly focused on capping emissions. At the federal level, the dynamics of the federal climate policy discussion have shifted as well. The Green New Deal has dominated the climate narrative, while some leading Republicans have begun pivoting the conversation on the right to a focus on solving climate change via innovation. There are still divides within each party, but there might be a fragile moment of opportunity to work on federal climate policy. Private-sector engagement with members of Congress will be important to pressure and educate all to find common ground and advance solutions. Climate advocates also need to put many different policy solutions on the table so Republicans and Democrats can find ones they both can agree on. The parties can build on the clean energy successes of 2018 (e.g., increased clean energy R&D funding, new incentives for CCUS and advanced nuclear) to achieve new policy wins, including ones focused on innovation, infrastructure, taxes, and perhaps other areas. Even if those policies are piecemeal measures, they can move things in the right direction and build a broader political foundation for future action. The key is to figure out the social and political alchemy that puts policy and technological solutions together in a way that gets broad enough support, creates a coherent and effective enough set of actions and capital deployment, and achieves enough progress in reducing GHG emissions.

ROCKY MOUNTAIN INSTITUTE

THE GROWING MARKET FOR CLEAN ENERGY PORTFOLIOS

ECONOMIC OPPORTUNITIES FOR A SHIFT FROM NEW GAS-FIRED GENERATION TO CLEAN ENERGY ACROSS THE UNITED STATES ELECTRICITY INDUSTRY



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EXECUTIVE SUMMARY

Clean energy is now cost-competitive with new gas-fired generation

For more than a decade, gas-fired power plants have dominated new generation investments for the US grid, and the trend is set to continue. Public announcements include approximately $70 billion of planned gas-fired generation investment through the mid-2020s.

However, due to dramatic price declines of wind, solar, and storage (WSS) technologies, clean energy portfolios (CEPs)—optimized combinations of WSS and demand-side management—are now similar in cost to new gas-fired power plants. Further, recent CEP projects prove that these clean technologies can reliably meet grid needs. As a result, new gas investments have slowed.

This study compares the economics of CEPs against every proposed gas plant in the United States

In 2018, RMI released ***The Economics of Clean Energy Portfolios***, which introduced a methodology for comparing CEP costs against new gas-fired generation and showcased four case studies across the United States. The present study expands upon the original work. We systematically optimize least-cost combinations of region-specific WSS, efficiency, and demand flexibility to provide grid services equivalent to every proposed combined-cycle and combustion turbine gas project in the United States. Our approach requires each portfolio to provide the same (or more) monthly energy as the proposed gas plant, match or exceed the gas plant's expected availability during the peak 50 demand hours (net of renewable generation), and provide the same level of grid flexibility.

Our approach forces CEPs to match the grid services of gas generation. The model therefore forces CEPs to compete only on gas generation's own metrics, and omits other clean technology benefits, such as the network

value of distributed technologies, the reduced risk of smaller projects, and carbon emissions reductions. Our modeling approach treats each proposed power plant independently, and assesses the economics of a CEP alternative based on how gas plants would be used when built with currently-planned growth in renewables. As such, our results are applicable to the economics and risks of near-term gas power plant investments, rather than the long-term role of gas generation in a future with a very high share (i.e., >50 percent) of renewable energy.

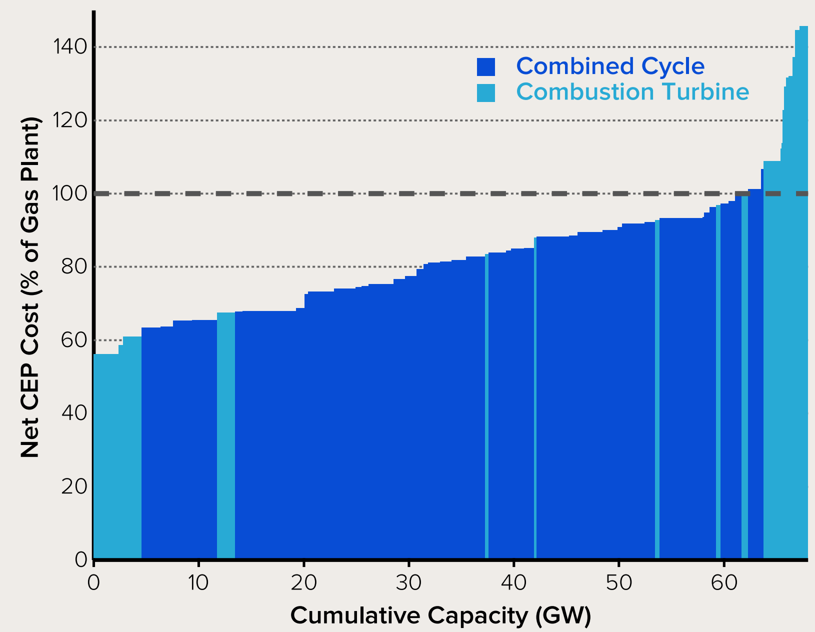
The analysis presents compelling evidence that 2019 represents a tipping point, with the economics now favoring clean energy over nearly all new US gas-fired generation. We present seven key findings:

1. CEPs are lower cost than 90 percent of the proposed 68 gigawatts (GW) of gas-fired power plant capacity

We find that CEPs are lower cost than 90 percent of proposed gas-fired generation at the proposed plant's in-service date (Figure ES 1). Investment in CEPs instead of new gas capacity would save customers over $29 billion and reduce CO_2 emissions by 100 million tons (MT)/year—equivalent to ~5 percent of current annual emissions from the power sector.[1]

FIGURE ES 1

NET CEP COST AS PERCENTAGE OF EQUIVALENT GAS PLANT COSTS AT PLANNED GAS BUILD IN SERVICE YEAR[2]



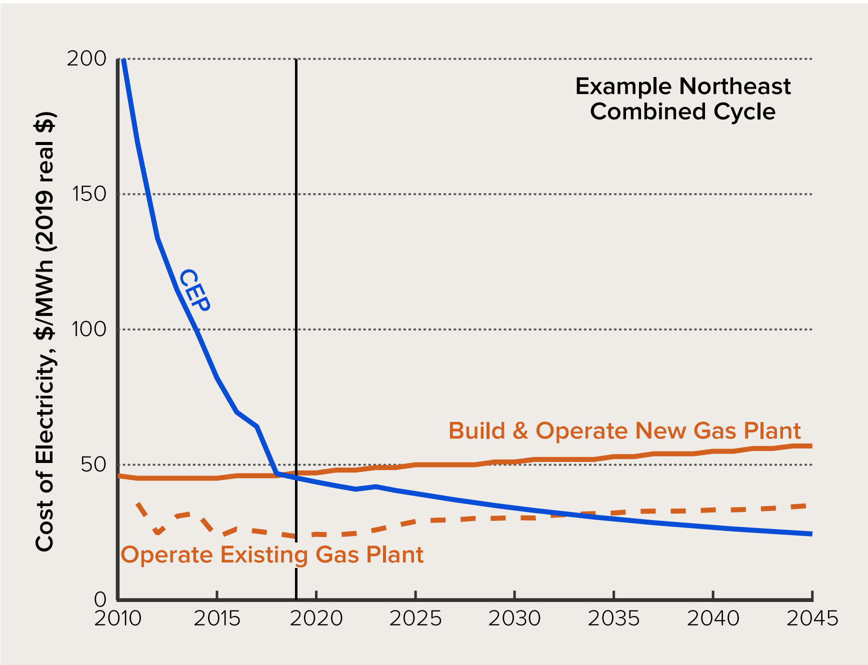
[1] Each case is analyzed independently, but we present aggregate results in this and subsequent findings by summing case study results across all 88 gas plants. This is reasonable because the 88 plants would 1) make up only ~7 percent of installed US generation capacity, limiting the impact of interactions between CEPs, and 2) we restrict the selection of CEP resources to ensure they are distinct from resources chosen in other CEPs.

[2] Net cost is shown here as total net present costs of the CEP compared to the gas plant, net of value from energy provided by the CEP and not provided by the gas plant; see Methodology section for details.

2. 2019 represents a tipping point for CEP economics

FIGURE ES 2

HISTORICAL AND PROJECTED EVOLUTION OF CEP COSTS



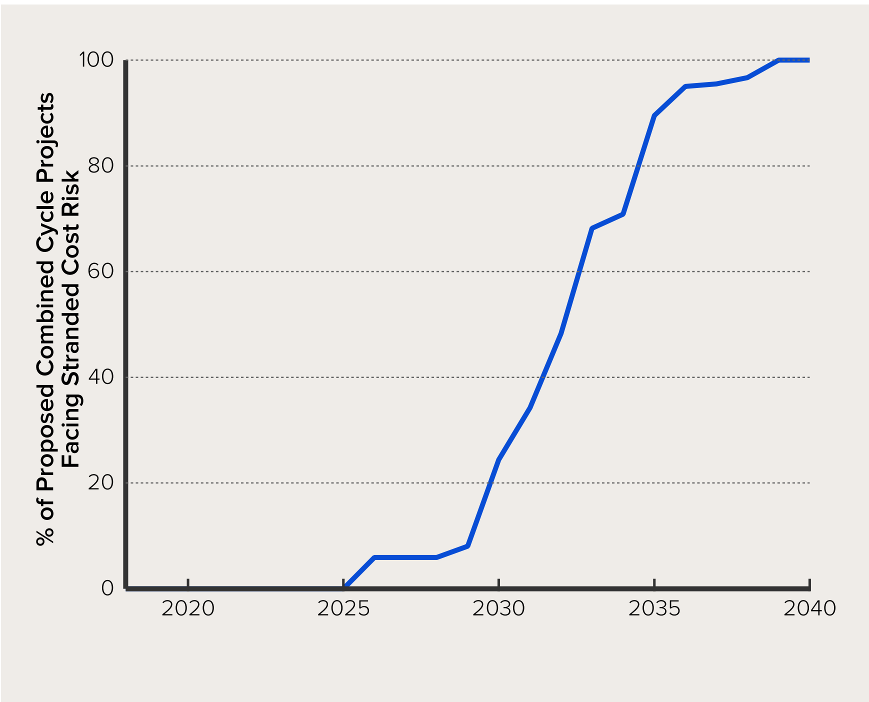
Note: The "kink" in the in the CEP cost curve in 2018 reflects the difference between historical cost decline rates for renewables and storage, and the much more moderate future cost decline rates predicted by technology analysts.

We find that the economics of new generation technologies in the United States are at a tipping point. Figure ES 2 compares the historical and projected costs of a representative CEP and the new combined-cycle plant it could replace for the years 2010 through 2045. The CEP's cost has declined by approximately 80 percent in the past decade, and, as of 2019, is lower than the costs of building and operating a new gas plant. Further, this typical CEP is likely to outcompete just the go-forward operating costs of a combined-cycle gas generator by the early 2030s. A number of factors, including continued fast clean technology cost declines or carbon pricing, would accelerate this timeline.

3. CEPs are likely to undercut the operating costs of over 90 percent of proposed new combined-cycle capacity by 2035, creating stranded asset risk for investors

FIGURE ES 3

PERCENT OF PROPOSED COMBINED-CYCLE GAS TURBINES (CCGTS) FACING STRANDED COST RISK IN EACH YEAR 2020–2040



Just as falling natural gas prices have limited the economic life of legacy coal assets and led to a wave of coal plant retirements, falling clean energy costs are likely to compromise the economic position of gas generation. For each proposed combined-cycle plant, we estimate the year in which the plant's operating costs will be higher than the costs of a new-build CEP that provides the same services (Figure ES 3). We find that nearly all combined cycles will be economically precarious well before they are fully paid for.[3] In 2035, it will be more expensive to operate 90 percent of proposed combined-cycle generation than to build new CEPs. We note that this analysis likely understates the economic case for future clean energy economics because it assumes a dramatic slowing of clean energy cost declines (Figure ES 2) and ignores the impact of potential local or national climate policies.

These economic trends imply significant risk for gas project investors. If gas generators are cost-effectively replaced by CEPs at a cost savings to customers, investors will be unable to meet the revenue targets needed to pay off the remaining gas plant book value and may not be able to cover outstanding debt or provide return on equity to investors. If planned projects are built, investors will likely face tens of billions of dollars' worth of stranded assets in the 2030s, as running these gas plants quickly becomes more expensive than building new CEPs.

[3] Conservatively assuming a 20-year planned economic life

4. The case for CEPs is strong across a range of modeling inputs

We analyzed the sensitivity of CEP economics against variations in all key model inputs, and found that in all cases, CEPs are robust against changes in component technology prices and gas prices. Our sensitivity analysis highlights a key value of piecemeal, modular clean energy investments. Unlike lump-sum investments in new gas-fired power plants, if one component of the CEP is more or less expensive than expected, it is possible to reoptimize the portfolio composition. In comparison, the economics of gas assets rely on a single capital expenditure and a single fuel source.

We also find that if clean technologies continue their recent, fast cost declines instead of following much slower industry projections (the difference explains the "kink" in the Figure ES 2 CEP curve), the case for CEPs is further accelerated.

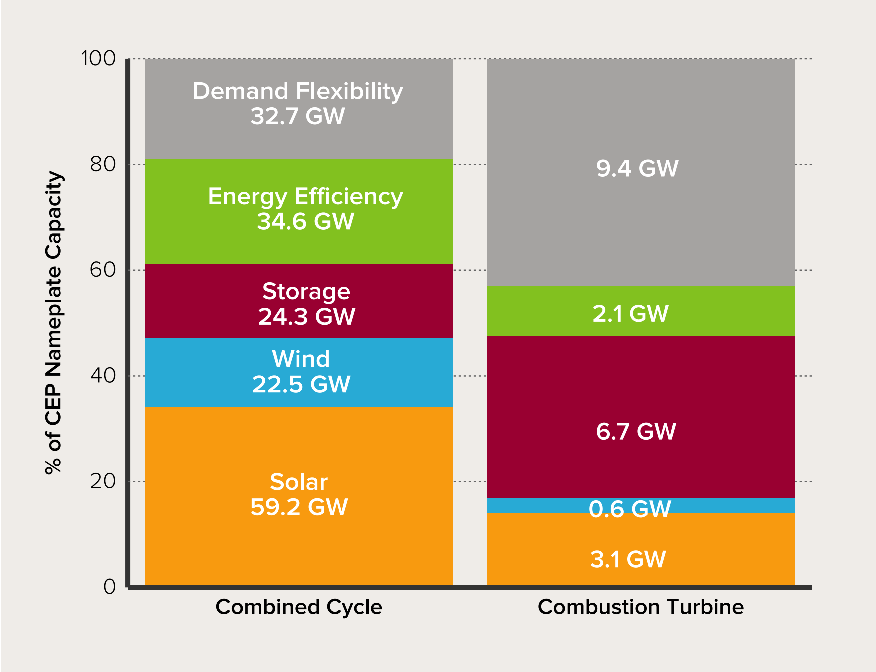
5. Ignoring the value of energy efficiency (EE) and demand flexibility shrinks the near-term market for CEPs to replace new gas by 70 percent and delays the economic opportunity by eight years

We consider portfolios of only WSS that omit EE and demand flexibility. Efficiency and demand flexibility are among the most cost-effective resources available to utility planners and investors, but usually require favorable state policies to achieve scale. If these cost-effective demand-side management resources are ignored, WSS is competitive with only 25 percent of proposed new gas plant capacity, compared with 90 percent for CEPs that include demand-side management. Using industry-standard projections for cost declines, we find it takes an additional eight years, on average, for WSS to reach cost parity with proposed gas plants.

6. CEP composition varies widely by region; all five clean technologies play important roles

FIGURE ES 4

AGGREGATE COMPOSITION OF CEPS ACROSS THE UNITED STATES



Note: More capacity, in megawatts (MW), of CEP resources is usually required to replace a given amount of gas capacity because the capacity factor (CF) of renewables is lower, though the levelized cost per MW is usually also lower.

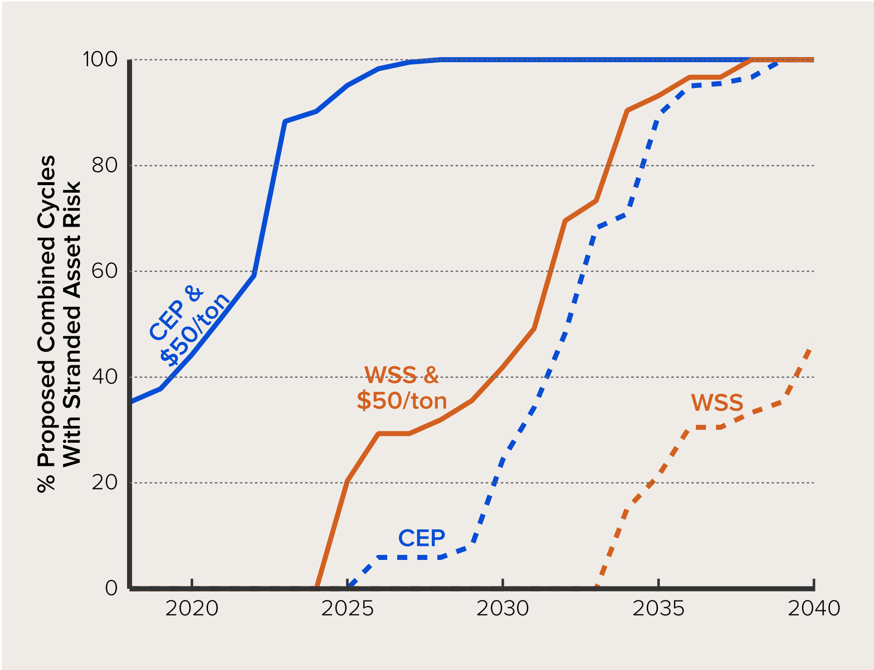
Figure ES 4 shows the aggregated resources that compose the CEPs equivalent to the proposed 56 GW of combined-cycle plants and 12 GW of combustion turbine plants. In total, CEPs designed to replace combined-cycle gas projects leverage low-cost wind and solar resources as well as EE. CEPs designed to replace lower-capacity factor, combustion turbine gas projects tend to favor storage and demand flexibility to provide peak-hour capacity.

Regional differences in least-cost CEP composition reflect both regional resource quality as well as the existing and predicted adoption of renewables. For example, Western region CEPs contain little new solar because significant existing solar capacity in California makes additional solar resources comparatively less valuable. In contrast, Texas CEPs prioritize solar relative to wind because of the large amount of existing and predicted wind capacity in Texas.

7. Carbon pricing bolsters the case for CEPs and accelerates stranded asset risk

FIGURE ES 5

TIMELINE OF WHEN GAS PLANT OPERATING COSTS EXCEED NEW-BUILD CEP INVESTMENT COSTS, WITH SENSITIVITIES FOR CO_2 PRICING AND EE AND DEMAND FLEXIBILITY



Our central analysis case assumptions do not include any explicit or implicit price on carbon emissions; even without carbon pricing, CEPs outcompete 90 percent of proposed gas-fired generation capacity. As a sensitivity, we assessed the impacts of imposing a $50/ton price on direct CO_2

emissions—on par with emissions prices used for planning in leading US jurisdictions. We do not account for upstream methane leakage. Figure ES 5 shows the implications; even a modest price on carbon pulls forward the timing of stranded asset risk for new-build gas-fired power plants by 5–10 years. For all-resource CEPs (blue lines), a $50/ton carbon price accelerates the economic risk for gas by 10 years so that 90 percent of plants are uneconomic in the early 2020s and all combined cycles are uneconomic in 2030. Even without EE and demand flexibility (orange lines), ~50 percent of proposed gas plants would be outcompeted by WSS in the early 2030s.

Implications and recommendations

The currently strong and quickly growing economic case for CEPs has significant implications for how investments in the electricity system are planned, incentivized, and regulated. The changing economics present an immense near-term opportunity—if the industry can quickly prioritize new, least-cost resources. On the other hand, there are significant risks if the industry is slow to evolve and continues to prioritize gas plant investments.

Informed by our findings, we suggest the following practices:

For vertically integrated utilities: Adopt emerging best practices with all-source, technology-neutral procurement

In leading vertically integrated utility service territories, where utilities invest in generation and regulators allow cost recovery through customer rates, utilities and their regulators are pioneering all-source, competitive bidding procurement processes where the economic advantages of CEPs emerge naturally. These procurement processes include the following proven steps:

1. **Define necessary grid services, not resource characteristics.** Start the planning and procurement process by specifying the services required, rather than characteristics of legacy generators that have historically provided them. Defining the need, not the solution, is crucial to ensuring the least-cost outcome.
2. **Create a level playing field for all resources.** Utility modeling tools must appropriately capture the capabilities of new, clean energy technologies, including storage, efficiency, and demand flexibility.
3. **Use competitive bidding to discover true resource prices and keep customer costs low.** Competitive bidding processes and real market input are essential to define the pricing assumptions used in planning and procurement.

For state utility regulators: Account for the significant risk that uneconomic gas generation will increase customer rates

Our analysis shows clean energy is lower cost than new gas-fired generation today and that its cost advantage will only increase with time. Before approving or rate-basing new gas generation, we suggest that regulators consider carefully whether gas generation is truly the lowest-cost way to meet the required grid services. Further, regulators should consider the risks of near-term gas investments, given the likelihood of continued clean energy cost declines and the potential for future carbon pricing. If new gas does appear marginally economic today, regulators may wish to mitigate risks to rate payers by 1) delaying approval of new gas investments, if possible; 2) requiring accelerated amortization schedules that reflect the limited economic life of new gas-fired power plants; and/or 3) changing risk allocation to protect customers.

For utilities and regulators: Embrace the value of demand-side resources in optimizing power supply portfolios

Historically, resource planning tools have not treated efficiency and demand response as resources on equal footing with centralized generation. Further, most cost-recovery regulation and utility business models do not incentivize utilities to reduce energy use. New incentives and mandates for demand-side resource investment, including performance incentive mechanisms and other forms of performance-based regulation, can provide utilities a profit motive for prioritizing and deploying these least-cost resources. These regulations can also encourage utilities to value other distributed energy resources (DERs), such as behind-the-meter solar and storage, in resource planning processes.

For wholesale market stakeholders: Restructure rules to encourage technology-neutral market competition to meet system needs
Approximately 60 percent of proposed gas-fired capacity is slated for construction in territories with restructured power markets, including the Northeast and Texas, where power plant investors respond to market signals for new capacity and the most cost-effective generation is deployed to meet demand. Unfortunately, the rules in these markets were designed to encourage competition primarily between fossil, nuclear, and hydro generation. With the dramatic declines in clean energy costs and demonstrated ability of these resources to meet grid needs, it is time to update market rules to promote technology-neutral competition for grid services, including demand side efficiency and flexibility. For example, the Federal Energy Regulatory Commission's (FERC's) new storage participation rules are an opportunity to test whether existing participation models match actual grid needs, or whether new models are needed to capture the full value of storage.

For merchant gas investors: Carefully consider the risk that new gas generation will be underused or stranded
We find that CEPs are lower cost than new generation today, and that clean energy is very likely to undercut the go-forward cost of electricity from deployed gas in the coming 10–15 years. Therefore, even if other estimates suggest new gas generation will be profitable given today's clean technology prices, building new gas today is a bet against any of the following three events:

- **Carbon pricing:** Even a modest carbon price (<$50/ton) accelerates the year in which new gas projects become uneconomic by 5–10 years.
- **Continued cost declines of clean energy:** Slightly faster learning rates for wind, solar, and batteries, splitting the difference between recent history and analyst forecasts, would reduce the expected economic lifetime of new gas plants by five years.
- **Market rules allowing full resource participation:** Current wholesale market rules favor legacy grid resources. The lag between market rule changes delays the transition to new technologies. However, participation rules for storage, demand flexibility, and EE are being tested and improved. As these rules are implemented, CEPs will become even more competitive in organized markets

Any one of these events would accelerate the economic case for CEPs and further degrade the profitability of new gas, and associated investor returns. Were two or three of these events to occur, the economics would tilt overwhelmingly in favor of CEPs, with dire consequences for investors in legacy assets.

Renewable Energy & Distributed Generation

Renewable Energy & Distributed Generation

Key Definitions from the Arizona Corporation Commission

Renewable Energy: An energy resource that is replaced rapidly by a natural, ongoing process and that is not nuclear or fossil fuel.

Distributed Generation: Electric generation cited at a customer premises, providing electric energy to the customer load on that site or providing wholesale capacity and energy to the local Utility Distribution Company for use by multiple customers. Includes rooftop solar systems.

Key Arizona Statistics

Arizona Energy Mix, 2018 from Energy Information Administration (EIA):

- 0.2% Biomass
- 0.5% Wind
- 4.6% Solar
- 6.2% Hydroelectric
- 27.4% Coal
- 27.7% Nuclear
- 33.4% Natural Gas

Numbers on Arizona Solar from the Solar Energy Industries Association (SEIA):

- 3rd in U.S. for installed solar capacity - 4,645 MW
- 6th in U.S. for solar jobs - 7,777 jobs
- 10th in U.S. for number of solar companies - 473
- $12.5 billion invested all-time
- $1.1 billion invested in 2019
- 150,000+ Arizona homes with solar installed

Significant Policies & Opportunities Under Consideration in Arizona

- *Renewable Energy Standard & Tariff (REST)*. Adopted by the Arizona Corporation Commission (ACC) in 2006; requires regulated utilities to meet a 15% renewable energy standard by 2025. The REST includes a standard for 4.5% of sales to come from distributed generation, like rooftop solar. A very successful policy that has driven renewable energy development statewide while benefitting Arizona's economy and environment. The ACC is now considering a significant expansion of the REST to put Arizona in line with the current energy market and the policies of neighboring states.
- *Net Metering and Rooftop Solar Credits.* For years, net metering allowed customers to receive 1-to-1 credits for excess solar energy produced by their home solar array. In recent years, the Arizona Corporation Commission and Salt River Project eliminated net metering and added fees for new solar customers. This led to fewer solar installations and longer payback periods for those investing in solar. The solar export credits for regulated utility customers with APS, TEP and UNS are declining each year and are good for only 10 years. The SRP solar rates have the worst payback periods in the state because of their high fixed fees and low solar credits. Without policy action, Arizonans will find it harder to go solar as time goes on.
- *Community Solar.* Many Arizonans currently do not have the option to lower their energy bills with solar, because they rent, live in an apartment complex, or don't have access to capital or financing. Community Solar is a tool being used in many states to allow third parties to develop mid-sized solar arrays and offer subscriptions to customers. Credits are then applied to the customer's utility bill, which can more than offset the cost of the subscription. Right now, some utilities offer "Community Solar" programs but charge a premium rather than offer a credit.
- *Distributed Battery Storage.* Many Arizona households that install solar are also considering a battery storage system. Battery storage can be charged by solar during the day and provide home backup power if the grid goes down. Battery storage can also provide a service to the power grid, by providing energy to the utility during times of high demand. In other states, utilities and third parties have begun aggregating distributed battery storage units and crediting customers for allowing the utility to use stored energy during times of need, such as on the hottest days of the year. Pairing distributed storage with other Demand Side Management resources can limit the need for utilities to buy expensive power on the market during times of high demand, or the need to invest in costly peaker gas power plants that only get used a few times of year.

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Arizona Renewable Energy Standard and Tariff: 2020 Progress Report

STRATEGEN

Prepared for:

Ceres

February 20, 2020

Arizona Renewable Energy Standard and Tariff: 2020 Progress Report

Prepared for:

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Executive Summary

The Arizona Renewable Energy Standard and Tariff ("REST"), established in 2006, has been a key driver of investments in renewable energy ("RE") technologies in the state. Arizona Public Service ("APS") and Tucson Electric Power ("TEP") together comprise nearly half of Arizona retail electricity sales and are both under the jurisdiction of the Arizona Corporation Commission ("ACC"). As such, they are subject to the 15% RE standard by 2025 established by REST. As of 2018, both APS and TEP exceeded REST requirements with RE resources totaling 14.3% and 15.8% of their retail sales, respectively.[1]

Implementation of the REST has delivered significant benefits in the form of avoided energy and generation capacity costs, reduced carbon emissions, reduced criteria air pollutants, water savings, increased investment in the state for a growing new industry, and technology cost reductions. Based on the benefits which could be readily quantified, Strategen estimates that from 2008 to 2018, gross benefits to utility customers and the public from implementing the REST have totaled over $1.5 billion for APS and over $469 million for TEP.[2]

From 2008 to 2018, gross benefits to utility customers and the public from implementing the REST have totaled nearly $2 billion.

Benefits of the REST are evident in several areas:

- **AVOIDED FUEL COSTS:** Adoption of renewable energy under the REST achieved significant cost savings from avoided fuel costs associated with conventional electricity production. In APS territory this contributed to $787 million in savings; in TEP territory it contributed to $235 million.

- **REDUCED PEAK DEMAND COSTS:** By 2018, both APS and TEP had renewable resources that equaled about 9% of their total peak demand. Renewables displaced capacity resources and led to cumulative avoided conventional peak generation capacity costs from 2008-2018 that equaled $297 million for APS and $82 million for TEP.

- **REDUCED CARBON EMISSIONS:** The displacement of conventional fossil fuel generation with renewable generation has also led to CO_2 emissions reductions in Arizona, with the REST responsible for an estimated 3% reduction in annual tons emitted (economy-wide) from 2008 to 2016. Using a relatively conservative value for the social cost of carbon, the societal benefit from these avoided CO_2 emissions equates to $234 million from APS and $75 million from TEP.

- **REDUCED AIR POLLUTANTS:** Criteria pollutant emission reductions (SOx, NOx and PM2.5) from increased clean energy adoption have resulted in health-related benefits valued at$185 million for APS and $61 million for TEP.

[1] For REST compliance purposes, REST-eligible resources are slightly below these levels as explained in Section 3.1.

[2] This reflects a combination of direct benefits to these utilities' customers (e.g. reduced fuel costs), as well as societal benefits experienced by the public at large (e.g. reduced air pollution). Gross benefits do not reflect the incremental costs to implement the REST.

- **REDUCED WATER CONSUMPTION:** On an annual basis, the APS and TEP renewable energy portfolios are saving more than 7,000 acre-feet (>8.6 million cubic meters) of water, a precious and scarce resource in the Southwest desert.

- **BILLIONS OF DOLLARS INVESTED:** Due to the support of the REST, the Arizona solar industry has thrived with an estimated $11.6 billion in investments, stimulating job growth and market development.

- **REDUCED CLEAN ENERGY COSTS:** From 2008 to 2018, median solar PV installation costs in Arizona declined by 53%, helping lower the price of PV projects state-wide.

Importantly, the benefits summarized above and attained through the REST were achieved with minimal impact to the ratepayer. REST surcharges have comprised a very small fraction of customer bills to date, falling within the 2-3% range for APS and 3-5% range for TEP.

Strategen anticipates that the benefits of deploying additional renewable energy in the future will significantly exceed the costs if implemented in a smart and strategic manner that integrates lessons learned from REST implementation to date. Going forward, the deployment of renewable resources ramping up to 45% by 2030 could result in a billion dollars of net benefits of generation costs alone for Arizona in the next ten years.[3]

[3] Not including additional costs for transmission

The Economic Benefits of Arizona Rural Renewable Energy Facilities

March 2019

Prepared for:

THE WESTERN WAY

Conservative Stewards of the Western Environment

Yuma County Chamber of Commerce Since 1905

Prepared By:

Development Research Partners

Development Research Partners specializes in economic research and analysis for local and state government and private sector businesses. Founded in 1994, Development Research Partners combines extensive experience in real estate economics and economic development to provide clients with insightful and strategic consulting services in four areas of expertise:

- **Economic and Demographic Research**

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Economic and Fiscal Benefits of Rural Renewable Energy Facilities in Arizona

- From 2001 to 2017, the total direct and indirect benefits of rural renewable energy development activity in Arizona was an estimated $9.4 billion in total output ($4.6 billion direct output + $4.7 billion indirect and induced output) produced by 17,971 employees (9,054 direct employees + 8,917 indirect employees) earning a total of about $1.2 billion ($717.2 million direct earnings + $477 million indirect earnings).

  The benefits included a direct fiscal benefit to Arizona of an estimated $16.7 million in transaction privilege and use tax revenue.

- In 2018, the total direct and indirect benefits of annual rural renewable energy operations in Arizona will be an estimated $63.3 million in total output ($39.5 million direct output + $23.8 million indirect and induced output) produced by 702 employees (234 direct employees + 468 indirect employees) earning a total of about $33.5 million ($15.1 million direct earnings + $18.4 million indirect earnings).

  The benefits will include a direct fiscal benefit to schools in Arizona of an estimated $882,000 in property tax revenue.

Case Study of the Potential Economic and Fiscal Benefits of a new 100 MW-Solar Photovoltaic Energy Facility with 30 MW of Battery Storage in Yuma County

- The total direct and indirect benefits of construction activity associated with a 100 MW-solar PV energy facility with 30 MW of battery storage in Yuma County could be an estimated $9.1 million in total output ($4.4 million direct output + $4.7 million indirect and induced output) produced by 22 employees (12 direct employees + 10 indirect employees) earning a total of about $1.3 million ($798,400 direct earnings + $510,000 indirect earnings) during the construction period.

- The total direct and indirect benefits of annual operations for a new 100 MW-solar PV energy facility with 30 MW of battery storage in Yuma County could be an estimated $3 million in total output ($1.9 million direct output + $1.1 million indirect and induced output) produced by 30 employees (9 direct employees + 21 indirect employees) earning a total of about $1.5 million ($689,000 direct earnings + $842,000 indirect earnings).

  The benefits will include an annual direct fiscal benefit to Yuma County of an estimated $165,700 in property tax revenue.

  In addition to the direct county benefit, there will also be a benefit to local schools and other property tax districts in the county. Based on average primary and secondary rates in the county, local property tax districts will benefit from $677,500 in annual property tax revenue.

Renewable energy generation facilities are growing in importance to communities across Arizona, including those in rural areas of the state. Renewable energy capacity is expanding in Arizona, particularly from non-hydroelectric renewable sources such as solar and wind. Since 2000, net electricity generation from non-hydroelectric sources increased from close to 0 percent of total net generation to 4.2 percent in 2016.[1] Renewable energy generation in Arizona is expected to continue to grow as Arizona has implemented policies to encourage renewable development. The state has a renewable portfolio standard that requires electric utilities to generate 15 percent of their energy from renewable resources by 2025. The state also has a variety of renewable energy tax incentives. Additionally, the rapidly falling cost of renewable energy technologies has also enhanced their viability. For instance, the average unsubsidized levelized cost of utility-scale crystalline solar photovoltaic facilities in the United States has decreased about 86 percent since 2009.[2] In many cases, the cost of utility-scale solar PV and wind technologies has fallen below plants utilizing traditional energy sources including natural gas combined cycle and peaking power plants. The intent of this study is to estimate the economic and fiscal benefits to Arizona of the construction and operations of utility-scale[3] solar and wind generation facilities that are located in rural areas of the state. In addition to a statewide analysis, this study includes a case study estimating the potential benefits a renewable facility could have in a rural county, demonstrating the potential benefits that can be realized in similar communities throughout the state.

ECONOMIC AND FISCAL IMPACT ANALYSIS DEFINED

Economic impact analysis is the analytical approach used to assess measurable direct and indirect benefits resulting from a project over a specific time period. Only those benefits that can be measured or quantified are included. Intangible benefits, such as enhancement of community character or diversification of the job base, are not included. The economic benefits are calculated within the framework of two categories of impacts and activities, which are construction and on-going operations.

Further, the economic impact is divided into direct and indirect impacts. The direct impacts include the direct spending for construction of a renewable facility and the direct spending for the on-going operations of the facility, including employee spending. The impact of constructing utility-scale renewable energy facilities has large but temporary impacts on the affected communities during the construction period. The construction impacts include the purchase of construction materials, construction worker earnings and resulting expenditures, and the tax implications of these purchases. The impact of on-going operations and maintenance of utility-scale renewable energy facilities has an annual impact on the affected communities over the life of the project. The on-going operations impacts include annual purchases of operational materials, replacement capital purchases, land-owner payments, employment and earnings, and the tax implications of these annual expenditures. The direct economic benefits of the facilities were estimated using the Jobs and Economic Development Impacts (JEDI) models developed by the National Renewable Energy Laboratory (NREL).

The economic impact does not stop with the direct impacts as the spending patterns associated with the renewable energy facility and its employees has multiplicative impacts on the region. Therefore, multiplier analysis

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[1] Energy Information Administration, State Energy Data System.

[2] Unsubsidized levelized cost of energy quantifies the net present value of the cost of a facility over its lifetime including initial capital investment and on-going operations. Reference Lazard's Levelized Cost of Energy Analysis – Version 11.0. https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf.

[3] According to the Office of Energy Efficiency & Renewable Energy in the U.S. Department of Energy, and for the purposes of this study, utility-scale renewable energy projects are defined as those 10 megawatts or larger. Utility-scale projects are generally associated with regulated electric utilities and independent power producers whose primary industry is electric power generation, transmission, and distribution.

is used to trace the impacts on businesses, organizations, and individuals affected by the facility as this impact works its way through the economy. The indirect and induced jobs and income flows generated are estimated using the RIMS (Regional Input-Output Modeling System) II multipliers developed by the Bureau of Economic Analysis of the U.S. Department of Commerce. This is the standard methodology for conducting multiplier analysis. The total economic benefits will be discussed in terms of the direct and indirect values of gross output, payroll or earnings, and employment in the specified region.

Fiscal impact analysis is used to assess the direct public revenues and public costs resulting from a project over a specific time period. A project may generate a broad array of public revenues ranging from sales/use tax, property tax, franchise fees, licenses and permits, and other charges for services. In turn, the local government provides a variety of public services such as police protection, public works, community social and recreational programs, and community development services, to name a few. This report includes a limited fiscal impact analysis, including estimates of direct sales/use tax revenue and property tax revenue generated only.

Development Research Partners utilized several sources of data for this study including company announcements, the State of Arizona, Lazard, the National Renewable Energy Laboratory, the U.S. Census Bureau, the U.S. Bureau of Labor Statistics, and the Energy Information Administration. Development Research Partners made every attempt to collect the necessary information and believe the information used in this report is from sources deemed reliable but is not guaranteed.

Some numbers in the study may not add exactly due to rounding, this analysis estimates the economic and fiscal benefits in nominal dollars.

Renewables on the Rise 2019

A Decade of Progress Toward a Clean Energy Future

ENVIRONMENT AMERICA
RESEARCH & POLICY CENTER

FRONTIER GROUP

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Executive Summary

Clean energy is sweeping across America and is poised for more dramatic growth in the coming years.

Wind turbines and solar panels were novelties ten years ago; today, they are everyday parts of America's energy landscape. Energy-saving LED light bulbs cost $40 apiece as recently as 2010; today, they cost a few dollars at the hardware store.[1] Just a few years ago, electric vehicles seemed a far-off solution to decarbonize our transportation system; now, they have broken through to the mass market.

Virtually every day, there are new developments that increase our ability to produce renewable energy, apply renewable energy more widely and flexibly to meet a wide range of energy needs, and reduce our overall energy use – developments that enable us to envision an economy powered entirely with clean, renewable energy.

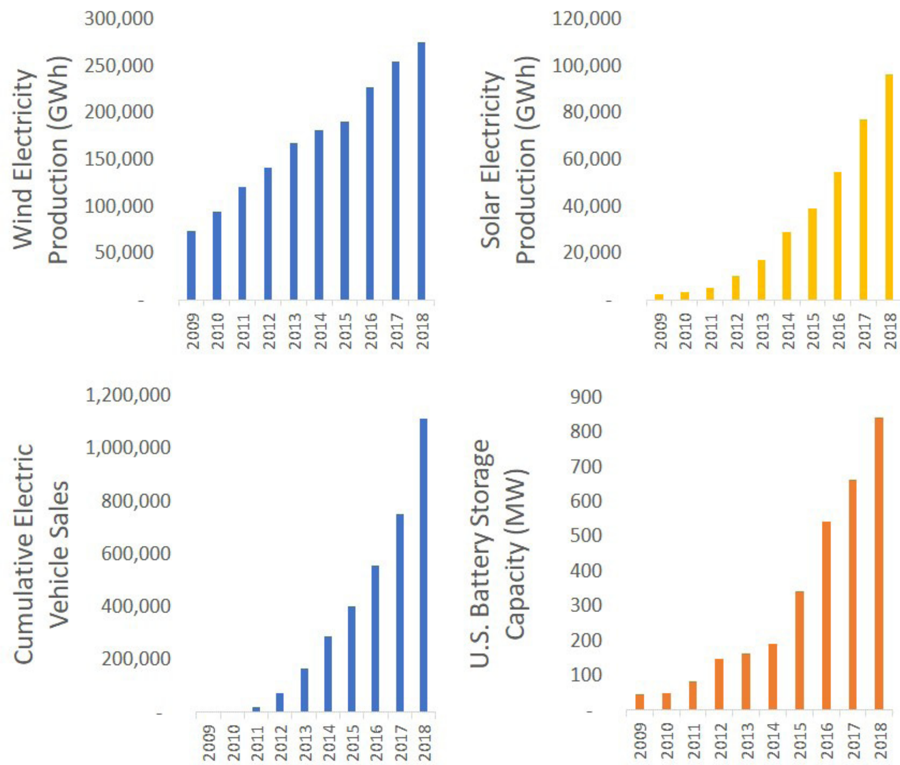
America produces **almost five times as much renewable electricity** from the sun and the wind as in 2009,[2] and currently wind and solar energy provide nearly **10 percent of our nation's electricity**.[3]

The last decade has proven that clean energy can power American homes, businesses and industry – and has put America on the cusp of a dramatic shift away from polluting energy sources. With renewable energy prices falling and new energy-saving technologies coming on line every day, **states, cities, businesses and the nation should work to obtain 100 percent of our energy from clean, renewable sources.**

The last decade has seen explosive growth in the key technologies needed to power America with clean, renewable energy.

- **Solar energy:** America produces over 40 times more solar power than it did in 2009, enough to power more than 9 million average American homes. In 2009, solar rooftops and utility-scale solar power plants produced 0.07 percent of U.S. electricity; in 2018, they produced 2.53 percent of America's power.[4] In 2019, the 2 millionth solar PV system was installed, and experts expect this number to double in five years.[5]
- **Wind energy:** America has more than tripled the amount of wind power it produces since 2009, enough to power over 26 million homes. In 2009, wind turbines produced 2.1 percent of the nation's electricity; in 2018, they produced 7.2 percent of America's power.[6]
- **Energy efficiency:** According to a survey by the American Council for an Energy-Efficient Economy (ACEEE), electric efficiency programs across the U.S. saved more than twice as much energy in 2017 as in 2009, as states ramped up their investments in efficiency.[7] In 2017, these programs saved enough electricity to power more than 2.5 million homes. Investments in natural gas efficiency programs have also realized massive energy savings, and in 2016 saved 340 million therms of natural gas – equivalent to the usage of over 500,000 homes.[8]

Figure ES-1: Clean Energy Technologies Have Seen Dramatic Growth Since 2009.[13]



- **Electric vehicles:** Building an economy reliant on clean, renewable energy means ending the use of fossil fuels for all activities, including transportation. There were over 361,000 electric vehicles sold in the U.S. in 2018, up from virtually none in 2009.[9] Electric vehicle sales surged by nearly 86 percent in 2018 over 2017.[10] In the first seven months of 2019, electric vehicle sales were up an additional 14 percent over that same period in 2018. In 2018, the millionth electric vehicle was sold in America.[11]

- **Energy storage:** Expanding the ability to store electricity can help the nation take full advantage of its vast potential for clean, renewable energy. The United States saw an 18-fold increase in utility-scale battery storage from 2009 to 2018.[12]

Clean energy leadership is not concentrated in one part of the country. Rather, it is distributed across the United States, in states with different economic and demographic makeups, driven by a combination of clean energy attributes and policies that have helped clean energy measures succeed.

- **Solar energy:** California, Arizona, North Carolina, Nevada and Texas have seen the greatest total increases in solar energy generation since 2009.[14] California's landmark "Million Solar Roofs" program, which accelerated the state's solar industry in the mid-2000s, along with its strong renewable electricity standard and other policies, helped to trigger the dramatic rise of solar power there.

- **Wind energy:** Texas, Oklahoma, Kansas, Iowa and Illinois experienced the greatest total increases in wind energy generation from 2009 to 2018.[15] Texas' policies to upgrade its grid to accommodate more wind power from rural west Texas played an important role in the boom.

- **Energy efficiency:** Rhode Island, Massachusetts, Vermont, Michigan and California saw the greatest increases in the share of electricity saved through efficiency measures, according to the American Council for an Energy-Efficient Economy. By 2017, Rhode Island was implementing efficiency measures designed to save the equivalent of 3 percent of 2016 statewide electricity sales.[16]
- **Electric vehicles:** California, New York, Washington, Florida and Texas have seen the most electric vehicles (EVs) sold.[17] Five of the top 10 states for EV sales require that a certain percentage of each automakers' sales be zero-emission vehicles, including California, which is home to nearly half of the nation's electric vehicles.[18]
- **Energy storage:** California, Illinois, Texas, West Virginia and Hawaii lead the nation in additions to battery storage since 2009, though the industry is still in its infancy.[19] By the end of 2018, California accounted for over a quarter of the nation's total battery storage capacity.[20] California's aggressive adoption of energy storage was due in part to a California Public Utilities Commission requirement that utilities increase energy storage capacity; additions also increased rapidly in response to the Aliso Canyon natural gas leak, for which energy storage was used to minimize grid disruptions.[21]

Rapid improvements in technology and plummeting prices for clean energy suggest that America has only begun to tap its vast clean energy potential.

- Nearly every segment of the clean energy market is experiencing rapid price declines. A National Renewable Energy Laboratory (NREL) survey of clean energy prices found that, from 2010 to 2018, the cost of distributed PV fell by 71 percent and utility-scale PV by 80-82 percent.[22] Lazard, a consulting firm that conducts an annual levelized cost of energy survey, found that the cost of land-based wind power fell by 66 percent during the same period.[23] It also reports that renewable sources like certain wind and solar energy technologies are "cost-competitive with conventional generation technologies."[24] In Idaho, for example, a record-breaking solar contract was signed in 2019, promising to deliver energy for 2.18 cents per kilowatt-hour.[25]
- One study by NREL found that the cost of wind energy is expected to fall 50 percent by 2030 from 2017 cost levels.[26] One study found that in most cases, building new wind and solar power is cheaper than running existing coal plants.[27] And renewable energy is only expected to get cheaper. Bloomberg New Energy Finance predicts that the cost of an average utility-scale solar plant will fall 71 percent by 2050.[28] It also estimates that by 2030, energy storage costs will fall by 52 percent.[29]
- Technology advances are making renewable energy technologies more efficient and effective. In 2007, the highest-capacity wind turbine in the world was 6 MW, with only one such test prototype actually in operation.[30] Today, an entire wind farm of 8 MW turbines is generating electricity off the coast of England; according to DONG Energy, which led the project, a single revolution of the blades on just one turbine can power a home for 29 hours.[31] This summer, GE expects to deploy the first prototype of its massive "Haliade-X" wind turbine, which has a capacity of 12 MW – enough to supply annual electricity for nearly 6,500 U.S. homes.[32]
- Advanced new products are also helping to reduce energy consumption. For example, light emitting diode (LED) lighting uses only a quarter the energy of a traditional, incandescent light and lasts up to 25 times longer.[33] From 2009 to 2015, the percentage of homes with at least one energy-efficient lightbulb in the house – typically either

an LED or CFL bulb – increased from 58 percent to 86 percent.[34] By 2027, the Department of Energy estimates that LEDs could save 348 terawatts of electricity, equivalent to the annual production of 44 large power plants.[35]

- America's renewable energy resources are enough to power the nation several times over. The technologies needed to harness and apply renewable energy are advancing rapidly. And researchers from a wide variety of academic and governmental institutions have developed a variety of scenarios suggesting renewable energy can meet all or nearly all of our society's needs.[36]

The U.S. should plan to meet all of its energy needs – for electricity, transportation and industry – with clean, renewable energy, and put policies and programs in place to achieve that goal.

- Repowering America with clean, renewable energy is a key strategy for phasing out carbon pollution by 2050 – a necessary step to prevent the worst impacts of global warming. Transitioning to clean, renewable energy will also improve our health by preventing hazardous air pollution, and increase our safety by protecting us from the hazards of extracting, transporting and processing dangerous fuels.

- While clean, renewable energy is advancing rapidly, fully replacing fossil fuels will require additional commitment and action. If the nation were to install as much renewable energy every year as we did in 2018, by 2050 America would be producing enough electricity to only meet 43 percent of today's electricity demand, before accounting for non-electricity energy needs.

- To accelerate progress, a growing number of businesses, cities and states are adopting bold renewable energy targets and goals. More than a dozen states substantially increased their renewable electricity standards. Hawaii, California, New Mexico, Maine, New York and Washington state have all set targets for 100 percent clean energy.[37]

- Local governments, utilities and companies are also taking action. 127 cities across the country have committed to 100 percent renewable energy, and six cities have already achieved it.[38] Several utilities, including Xcel Energy, Platte River Power Authority and MidAmerican Energy, have made commitments to source their electricity from carbon-free or renewable sources.[39] The organization RE100 has also collected 100 percent renewable energy commitments from 191 companies, including IKEA, Google, and Anheuser-Busch InBev.[40]

America has already made incredible progress toward getting its energy from clean, renewable sources. Policymakers at all levels should fully commit to repowering America with clean, renewable energy.

National Standard Practice Manual

For Benefit-Cost Analysis of Distributed Energy Resources

Summary

AUGUST 2020

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Acknowledgements

This *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (NSPM or the manual) is a publication of the National Energy Screening Project (NESP). The NESP is represented by a stakeholder group of organizations and individuals working to update and improve cost-effectiveness screening practices for distributed energy resources.

This manual incorporates and expands upon the guidance from the 2017 *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources*, which presented the NSPM Framework, fundamental benefit-cost analysis principles, and guidance specific to energy efficiency resources.

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This manual and related materials, including prior NSPM publications, are available at: www.nationalenergyscreeningproject.org/national-standard-practice-manual/.

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NSPM Summary

The purpose of this *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (NSPM, or the manual) is to help guide the development of jurisdictions' cost-effectiveness test(s) for conducting benefit-cost analyses (BCAs) of distributed energy resources (DERs). BCAs involve a systematic approach for assessing the cost-effectiveness of investments by consistently and comprehensively comparing the benefits and costs of individual or multiple types of DERs with each other and with alternative energy resources.

This manual includes information for conducting BCAs of single and multiple types of DERs and provides use case examples that illustrate BCAs under different combinations and applications of DERs. The DER types covered in this manual are: energy efficiency (EE); demand response (DR); distributed generation (DG); distributed storage (DS); electric vehicles (EV); and increased electrification of buildings including heating and cooling systems.

Distributed Energy Resources (DERs) are resources located on the distribution system that are generally sited close to or at customers' facilities. DERs include EE, DR, DG, DS, EVs, and increased electrification of buildings. DERs can either be on the host customer side of the utility interconnection point (i.e., behind the meter) or on the utility side (i.e., in front of the meter). DERs are mostly associated with the electricity system and can provide all or some of host customers' immediate power needs and/or support the utility system by reducing demand and/or providing supply to meet energy, capacity, or ancillary services (time and locational) needs of the electric grid.

DERs represent a critical component of the evolution of the electricity grid by allowing for a more flexible grid, enabling two-way flows of energy, enabling third parties to introduce and sell new electricity products and services, and empowering customers to optimize their end-uses and consumption patterns to lower their bills and utility costs.

This manual is built around a BCA framework (the NSPM BCA Framework) that defines the steps a jurisdiction can use to develop its primary cost-effectiveness test—the Jurisdiction-Specific Test (JST). The framework also provides guidance on how consider and develop secondary tests, where applicable. The NSPM BCA Framework includes a set of core principles that are the foundation for developing and applying cost-effectiveness tests for BCAs.

The NSPM is policy-neutral in that it does not recommend any specific cost-effectiveness tests or policies, but rather supports BCA practices that align with a jurisdiction's policy goals and objectives. The manual thus serves as an objective, technology-neutral and economically sound guidance document for regulators, utilities, consumer advocates, DER proponents, state energy offices, and other stakeholders interested in comprehensively assessing the impacts of DER investments.

This manual incorporates and expands upon the guidance from the 2017 *NSPM for Assessing Cost-Effectiveness of Energy Efficiency Resources* (NSPM for EE). Both documents are products of the National Energy Screening Project (NESP), a multi-year effort guided by an advisory group represented by a range of experts with varying perspectives involved in BCA of DERs.

This NSPM provides objective, policy- and technology-neutral, and economically sound guidance for developing jurisdiction-specific approaches to benefit-cost analyses of distributed energy resources.

Terminology and Applicability of the NSPM

This manual uses many terms that are commonly used within the electricity and gas industries. Key terms are defined in a Glossary and in relevant sections of the manual. Some of the terms used in the manual are more broadly defined than in other applications, as noted below.

NSPM Terminology

Jurisdiction refers broadly to any region or service territory that would be served by the DERs being analyzed. This includes a state, a province, a utility service territory, a city or a town, or some other jurisdiction covered by regulators or other entities that oversee DER initiatives.

Utility refers broadly to any entity that funds, implements, or supports DERs using customer or public funds that are overseen by regulators or other decision-makers. This includes investor-owned utilities; publicly owned utilities (e.g., municipal or cooperative utilities); program administrators; community choice aggregators; regional transmission organizations and independent system operators; federal, state, and local governments; and others. *Utility expenditures* refers to spending by any of these entities on DERs.

Regulator refers broadly to any entity that oversees and guides DER analyses. This includes legislators and their staff; public utility commissions and their staff; boards overseeing public power authorities, municipal or cooperative utilities, or regional grid operators; and federal, state, and local governments.

Host customer refers to any customer that has a DER installed and/or operated on their site. In some cases, these are program participants (such as in a DR or EE program) while in other cases there is no program (such as with EV owners).

Third parties refer to the broad range of independent providers such as aggregators or implementation, service, or technology providers.

The principles and concepts presented in this manual are relevant to:

1. DER programs, procurements, or pricing mechanisms associated with expenditures on behalf of the public or utility customers, whether by utilities or others. For simplicity, these are referred to these as ‘utility expenditures.’
2. Any jurisdiction where DERs are funded, acquired, or otherwise supported by electric or gas utilities or others on behalf of their customers.
3. All types of electric and gas utilities, including investor-owned and publicly owned utilities (e.g., municipal or cooperative utilities.)
4. All types of utilities, including utilities that are vertically integrated, transmission and distribution (T&D), or distribution-only utilities, or those serving as a distribution platform for host customers to access a variety of energy services and DERs from third parties (e.g., aggregators).
5. Single DER and multiple DER BCA analyses, where:
    - *Single-DER analyses* involve assessing *one DER type* in isolation from other DER types, relative to a static set of alternative resources.
    - *Multiple-DER analyses* involve assessing more than one DER type at the same time relative to a *static or dynamic* set of alternative resources. Multiple-DER analyses covered in this manual include multiple *on-site* DERs, non-wires solutions within a specific *geographic area*, and *system-wide* DER portfolios.

- *Dynamic system planning* involves assessing multiple DER types relative to a dynamic set of alternative resources. Under this approach, the goal is to optimize both DERs and alternative utility-scale resources as well. This practice is relatively nascent and still evolving.

While the NSPM addresses BCA for single and multi-DER scenarios, it does not address every nuance or application for DER investments.

Manual Contents

The NSPM includes five parts:

- Part I presents the NSPM BCA Framework, including fundamental principles and guidance on the development of primary and any secondary cost-effectiveness tests.
- Part II describes the full range of potentially relevant DER benefits and costs (i.e., impacts), and presents several cross-cutting considerations on how to account for certain impacts.
- Part III provides guidance on single-DER BCA for various types of DER technologies. These chapters provide guidance on key factors and challenges that affect the impacts of each DER type.
- Part IV provides guidance on multiple-DER analysis. It addresses the three main ways that multiple-DER analysis is conducted: for a customer site; for a geographic region; and for an entire utility service territory. Part IV also addresses, at a high level, dynamic system planning.
- Appendices provide further detail on topics that warrant additional explanation. The appendices also provide information and templates on reporting BCA results.

Part I: The NSPM BCA Framework

Part I presents the NSPM BCA Framework, comprising three elements:

1. A set of **fundamental principles** that serve as the foundation for assessing the cost-effectiveness of potential DER investments in an economically sound and policy-neutral manner;
2. A **multi-step process** for developing or informing a jurisdiction’s primary test—the Jurisdiction-Specific Test (JST)—as guided by the NSPM principles; and
3. Guidance on **when and how to use secondary tests** to inform (a) the prioritization of cost-effective DERs, as determined by a primary JST, and (b) decisions around marginally non-cost-effective DERs.

The **NSPM principles** in and of themselves do not determine a jurisdiction’s appropriate cost-effectiveness test for DERs. The NSPM principles are intended to be applied in a manner that takes into consideration the characteristics and circumstances of each jurisdiction’s approach to energy resources and can result in different JSTs for different jurisdictions.

Fundamental BCA Principles

The NSPM provides a set of fundamental BCA principles that represent sound economic and regulatory practices. The NSPM BCA principles presented in Table S-1 set the foundation for developing cost-effectiveness tests for BCA. The principles can be used to guide the application of cost-effectiveness testing, selection of a discount rate, and the reporting of the BCA results, and they can inform the process for prioritizing DERs to be implemented.

The NSPM BCA principles are not mutually exclusive as they contain some overlapping concepts. Further, there may be situations where it is necessary for jurisdictions to make tradeoffs between certain principles depending on specific situations.

Table S-1. NSPM BCA Principles

Principle 1	**Treat DERs as a Utility System Resource** DERs are one of many energy resources that can be deployed to meet utility/power system needs. DERs should therefore be compared with other energy resources, including other DERs, using consistent methods and assumptions to avoid bias across resource investment decisions.
Principle 2	**Align with Policy Goals** Jurisdictions invest in or support energy resources to meet a variety of goals and objectives. The primary cost-effectiveness test should therefore reflect this intent by accounting for the jurisdiction's applicable policy goals and objectives.
Principle 3	**Ensure Symmetry** Asymmetrical treatment of benefits and costs associated with a resource can lead to a biased assessment of the resource. To avoid such bias, benefits and costs should be treated symmetrically for any given type of impact.
Principle 4	**Account for Relevant, Material Impacts** Cost-effectiveness tests should include all relevant (according to applicable policy goals), material impacts including those that are difficult to quantify or monetize.
Principle 5	**Conduct Forward-Looking, Long-term, Incremental Analyses** Cost-effectiveness analyses should be forward-looking, long-term, and incremental to what would have occurred absent the DER. This helps ensure that the resource in question is properly compared with alternatives.
Principle 6	**Avoid Double-Counting Impacts** Cost-effectiveness analyses present a risk of double-counting benefits and/or costs. All impacts should therefore be clearly defined and valued to avoid double-counting.
Principle 7	**Ensure Transparency** Transparency helps to ensure engagement and trust in the BCA process and decisions. BCA practices should therefore be transparent, where all relevant assumptions, methodologies, and results are clearly documented and available for stakeholder review and input.
Principle 8	**Conduct BCAs Separately from Rate Impact Analyses** Cost-effectiveness analyses answer fundamentally different questions than rate impact analyses, and therefore should be conducted separately from rate impact analyses.

Process for Developing a Primary Jurisdiction-Specific Test

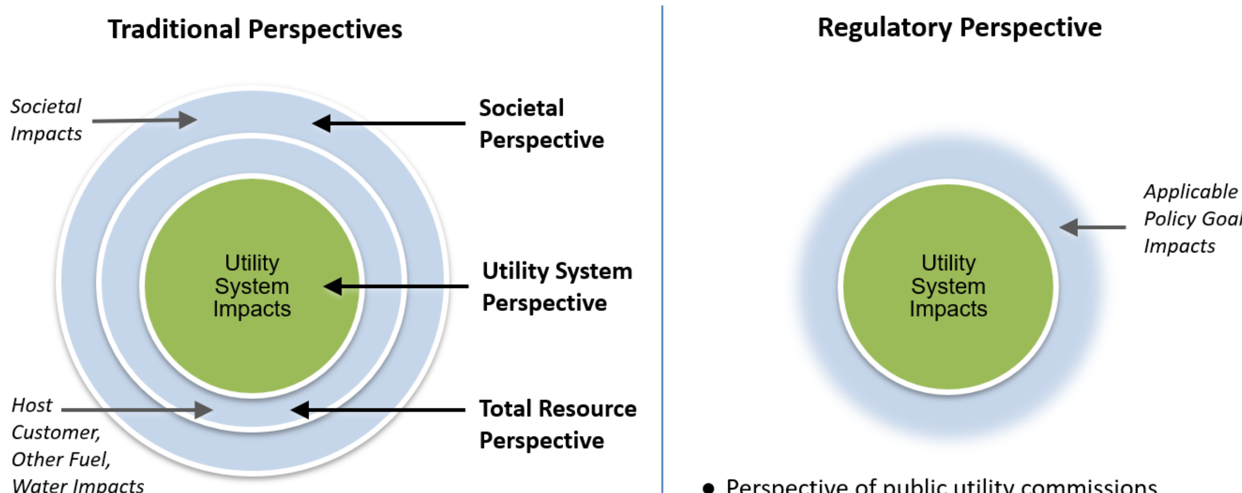
> The primary test answers the critical question: Which DERs have benefits that exceed costs and therefore merit utility acquisition or support on behalf of customers?

The NSPM presents a step-by-step process for developing a primary cost-effectiveness test (or modifying an existing primary test). Referred to as the 'JST', this test reflects the fundamental BCA principles in Table S-1.

This manual presents the regulatory perspective, which refers to the perspective of regulators or similar entities that oversee utility DER investment decisions. A JST should reflect the regulatory perspective to ensure proper accounting of the jurisdiction's applicable policy goals—as guided by statutes, regulations, organizational policies, utility resource planning principles and policies, and/or other codified forms under which utilities or energy providers operate.

Figure S-1 illustrates the regulatory perspective relative to traditional cost-effectiveness test perspectives.

Figure S-1. The Regulatory Perspective



- Three perspectives define the scope of impacts to include in the most common traditional cost-effectiveness tests.

- Perspective of public utility commissions, legislators, muni/coop boards, public power authorities, and other relevant decision-makers.
- Accounts for utility system plus impacts relevant to a jurisdiction's applicable policy goals (which may or may not include host customer impacts).
- Can align with one of the traditional test perspectives, but not necessarily.

Table S-2 presents the multi-step process for developing a JST. This process provides the flexibility for each jurisdiction to tailor its primary JST to its own goals and objectives.

Table S-2. Developing a Jurisdiction's Primary Test: A 5-Step Process

STEP 1	**Articulate Applicable Policy Goals** Articulate the jurisdiction's applicable policy goals related to DERs.
STEP 2	**Include All Utility System Impacts** Identify and include the full range of utility system impacts in the primary test, and all BCA tests.
STEP 3	**Decide Which Non-Utility System Impacts to Include** Identify those non-utility system impacts to include in the primary test based on applicable policy goals identified in Step 1: • Determine whether to include host customer impacts, low-income impacts, other fuel and water impacts, and/or societal impacts.
STEP 4	**Ensure that Benefits and Costs are Properly Addressed** Ensure that the impacts identified in Steps 2 and 3 are properly addressed, where: • Benefits and costs are treated symmetrically. • Relevant and material impacts are included, even if hard to quantify. • Benefits and costs are not double-counted. • Benefits and costs are treated consistently across DER types.
STEP 5	**Establish Comprehensive, Transparent Documentation** Establish comprehensive, transparent documentation and reporting, whereby: • The process used to determine the primary test is fully documented. • Reporting requirements and/or use of templates for presenting assumptions and results are developed.

When deciding whether to include a benefit or cost in a BCA test, it is important to distinguish between the *definition* versus *application* of the BCA test. Any impact that is deemed to be relevant should be included as part of the definition of the test. In some cases, a benefit or cost may be relevant but not material. *Material* impacts are those that are expected to be of sufficient magnitude to affect the result of a BCA. Impact determined to be immaterial should be documented, but not necessarily included in the application of the BCA test.

Secondary BCA Tests

The NSPM also provides guidance on how secondary tests can be used to help assess marginally cost-effective DERs or to prioritize across DERs. While a jurisdiction's primary test should be used to inform whether a utility should fund or otherwise support DERs, it does not have to be utilized in a vacuum. In some instances, secondary tests can help enhance regulators' and stakeholders' overall understanding of DER impacts by answering other questions regarding utility DER investments. Different tests provide different information about the cost-effectiveness and impacts of DERs. However, secondary tests should be used cautiously to ensure that they do not make the BCA decision-making process burdensome or undermine the purpose of the primary test.

This manual does not prescribe any one cost-effectiveness test. Because the JST is based upon each jurisdiction's applicable policy goals, and those goals can vary across jurisdictions, the test may take a variety of forms. Further, depending on a jurisdiction's applicable policy goals, the primary test may or may not align with traditional BCA tests (e.g., the Total Resource Cost test.)

Part II. DER Benefits and Costs and Cross-Cutting Considerations

Part II of the manual presents a catalog of the full range of benefits and costs that may be applicable to specific types of DERs. This catalog can be used as a reference when deciding which types of benefits and costs should be included in a jurisdiction's BCA test.

The catalog of impacts is presented in table format and supported with detailed descriptions of each impact type. Table S-3 shows the range of potential DER impacts to the electric utility system, along with descriptions of each impact. Similarly, Table S-4 and Table S-5 provide a summary of potential host customer and societal impacts, respectively. Part II also addresses natural gas and other fuel system impacts and specific host customer non-energy impacts (NEIs).

Table S-3. Potential DER Impacts: Electric Utility System

Type	Utility System Impact	Description
Generation	Energy Generation	The production or procurement of energy (kWh) from generation resources on behalf of customers
	Capacity	The generation capacity (kW) required to meet the forecasted system peak load
	Environmental Compliance	Actions to comply with environmental regulations
	RPS/CES Compliance	Actions to comply with renewable portfolio standards or clean energy standards
	Market Price Effects	The decrease (or increase) in wholesale market prices as a result of reduced (or increased) customer consumption
	Ancillary Services	Services required to maintain electric grid stability and power quality
Transmission	Transmission Capacity	Maintaining the availability of the transmission system to transport electricity safely and reliably
	Transmission System Losses	Electricity or gas lost through the transmission system
Distribution	Distribution Capacity	Maintaining the availability of the distribution system to transport electricity or gas safely and reliably
	Distribution System Losses	Electricity lost through the distribution system
	Distribution O&M	Operating and maintaining the distribution system
	Distribution Voltage	Maintaining voltage levels within an acceptable range to ensure that both real and reactive power production are matched with demand
General	Financial Incentives	Utility financial support provided to DER host customers or other market actors to encourage DER implementation
	Program Administration	Utility outreach to trade allies, technical training, marketing, and administration and management of DERs
	Utility Performance Incentives	Incentives offered to utilities to encourage successful, effective implementation of DER programs
	Credit and Collection	Bad debt, disconnections, reconnections
	Risk	Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks
	Reliability	Maintaining generation, transmission, and distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions

Table S-4. Potential Benefits and Costs of DERs: Host Customer

Type	Gas Utility or Other Fuel Impact	Description
Energy	Fuel and Variable O&M	The fuel and O&M impacts associated with gas or other fuels
	Capacity	The gas capacity required to meet forecasted peak load
	Environmental Compliance	Actions required to comply with environmental regulations
	Market Price Effects	The decrease (or increase) in wholesale prices as a result of reduced (or increased) customer consumption
General	Financial Incentives	Utility financial support provided to DER host customers or other market actors to encourage DER implementation
	Program Administration Costs	Utility outreach to trade allies, technical training, marketing, and administration and management of DERs
	Utility Performance Incentives	Incentives offered to utilities to encourage successful, effective implementation of DER programs
	Credit and Collection Costs	Bad debt, disconnections, reconnections
	Risk	Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks
	Reliability	Maintaining the gas or other fuel system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions

Table S-5. Potential Costs and Benefits of DERs: Societal

Type	Societal Impact	Description
Societal	Resilience	Resilience impacts beyond those experienced by utilities or host customers
	GHG Emissions	GHG emissions created by fossil-fueled energy resources
	Other Environmental	Other air emissions, solid waste, land, water, and other environmental impacts
	Economic and Jobs	Incremental economic development and job impacts
	Public Health	Health impacts, medical costs, and productivity affected by health
	Low-Income: Society	Poverty alleviation, environmental justice, and reduced home foreclosures
	Energy Security	Energy imports and energy independence

In addition to describing the range of potential DER impacts, Part II also addresses key cross-cutting benefit and cost issues, including the following:

- *Temporal and Locational Impacts of DERs*: Several of the benefits and costs of some DERs can vary significantly depending on when the DER operates and where it is located. DER benefits and costs should be estimated using temporal and locational detail sufficient to adequately represent the DER operating patterns and consequent benefits and costs.
- *Interactive effects between individual DERs*: Some DERs can have interactive effects on other DERs in terms of affecting avoided costs, affecting the magnitude of kWh and kW impacts, and enabling the adoption of other DERs. These interactive effects should be accounted for in BCAs for those instances where they are likely to have a material effect.

- *Air emission impacts*: Greenhouse gas (GHG) and other air emission impacts will depend upon when the DER operates and which energy resources are displaced at that time. Estimates of GHG and other air emission impacts should account for the temporal and marginal DER impacts in as much detail as necessary to reflect these effects.
- *Renewable generation impacts*: DERs can support renewable electricity generation by providing grid flexibility and ancillary services. DERs can also reduce (or increase) the need to curtail renewable resources during times when renewable generation exceeds customer load. These impacts on renewable generation should be accounted for when they are expected to have a material effect on the BCA results.
- *Discount rates*: The choice of discount rate to use for a BCA can often have a very large effect on the result of the analysis. This choice should be guided by the jurisdiction's applicable policy goals and the regulatory perspective.

DER impacts identified for inclusion in a jurisdiction's BCA should ideally be estimated in monetary terms. Monetary values provide a uniform way to compile, present, and compare benefits and costs. While some DER impacts are difficult to quantify in monetary terms—either due to the nature of the impact or the lack of available information about the impacts—approximating hard-to-quantify impacts using best available information is preferable to arbitrarily assuming a value, including assuming that the relevant impacts do not exist or have no value. Further, some approximation may be necessary to ensure symmetry in the treatment of benefits and costs for certain relevant impacts.

Part III: BCA for Specific DER Types

Part III of the NSPM contains five chapters that discuss individual characteristics and impacts of each DER type covered in this manual: EE, DR, DG, DS, and electrification (including managed charging and discharging of EVs). Part III describes and provides guidance on key factors and challenges that affect the impacts of each DER type.

Table S-6, Table S-7, and Table S-8 show the range of benefits and costs in terms of their applicability to each DER. They indicate which impacts are typically a benefit, a cost, or either depending on the specific DER use case. The tables are a compilation of the DER-specific tables presented in Chapters 6–10 of the manual.

Table S-6. Potential Benefits and Costs: Electric Utility System

Type	Utility System Impact	EE	DR	DG	Storage	Electrification
Generation	Energy Generation	● (green)	● (orange)	● (green)	● (red)	● (red)
	Capacity	● (green)	● (green)	● (green)	● (orange)	● (red)
	Environmental Compliance	● (green)	● (orange)	● (green)	● (orange)	● (red)
	RPS/CES Compliance	● (green)	● (orange)	● (green)	● (red)	● (red)
	Market Price Effects	● (green)	● (green)	● (green)	● (orange)	● (red)
	Ancillary Services	● (green)	● (green)	● (orange)	● (orange)	● (red)
Transmission	Transmission Capacity	● (green)	● (green)	● (orange)	● (orange)	● (orange)
	Transmission System Losses	● (green)	● (green)	● (green)	● (orange)	● (red)
Distribution	Distribution Capacity	● (green)	● (green)	● (orange)	● (orange)	● (red)
	Distribution System Losses	● (green)	● (green)	● (green)	● (orange)	● (red)
	Distribution O&M	● (green)	● (green)	● (orange)	● (orange)	● (red)
	Distribution Voltage	● (green)	● (green)	● (orange)	● (orange)	● (red)
General	Financial Incentives	● (red)	● (red)	● (red)	● (red)	● (red)
	Program Administration Costs	● (red)	● (red)	● (red)	● (red)	● (red)
	Utility Performance Incentives	● (red)	● (red)	● (red)	● (red)	● (red)
	Credit and Collection Costs	● (green)	● (green)	● (green)	● (green)	● (green)
	Risk	● (green)	● (green)	● (orange)	● (green)	● (red)
	Reliability	● (green)	● (green)	● (orange)	● (green)	● (red)
	Resilience	● (green)	● (green)	● (green)	● (green)	○

● (green) = typically a benefit for this resource type; ● (red) = typically a cost for this resource type; ● (orange) = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type

Table S-7. Potential Benefits and Costs of DERs: DER Host Customer

Type	Host Customer Impact	EE	DR	DG	Storage	Electrification
Host Customer	Host portion of DER costs	● (red)	● (red)	● (red)	● (red)	● (red)
	Interconnection fees	○	○	● (red)	● (red)	○
	Risk	● (green)	○	● (orange)	● (green)	● (orange)
	Reliability	● (green)	● (orange)	● (green)	● (green)	● (orange)
	Resilience	● (green)	● (orange)	● (green)	● (green)	● (green)
	Tax Incentives	● (green)	● (green)	● (green)	● (green)	● (green)
	Host Customer NEIs	● (orange)	● (orange)	● (orange)	● (orange)	● (orange)
	Low-income NEIs	● (green)	● (green)	● (green)	● (green)	● (green)

● (green) = typically a benefit for this resource type; ● (red) = typically a cost for this resource type; ● (orange) = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type

Table S-8. Potential Benefits and Costs of DERs: Societal

Type	Societal Impact	EE	DR	DG	Storage	Electrification
	Resilience	🟢	🟢	🟢	🟢	🟠
	GHG Emissions	🟢	🟠	🟢	🟠	🟠
	Other Environmental	🟢	🟠	🟢	🟠	🟠
	Economic and Jobs	🟢	🟢	🟢	🟠	🟠
	Public Health	🟢	🟠	🟢	🟠	🟠
	Low Income: Society	🟢	🟢	🟢	🟢	🟢
	Energy Security	🟢	🟢	🟢	🟠	🟢

🟢 = typically a benefit for this resource type; 🔴 = typically a cost for this resource type; 🟠 = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type

Part IV: BCA for Multiple DER Types

The manual addresses BCA for different applications where multiple DER types might be combined, including:

- multiple on-site DER types, such as grid-integrated efficient buildings (GEB);
- multiple DER types in a specific geographic location in the form of a non-wires solution (NWS);
- multiple DER types across a utility service territory; and
- dynamic system planning practices that can be used to optimize DERs and alternative resources.

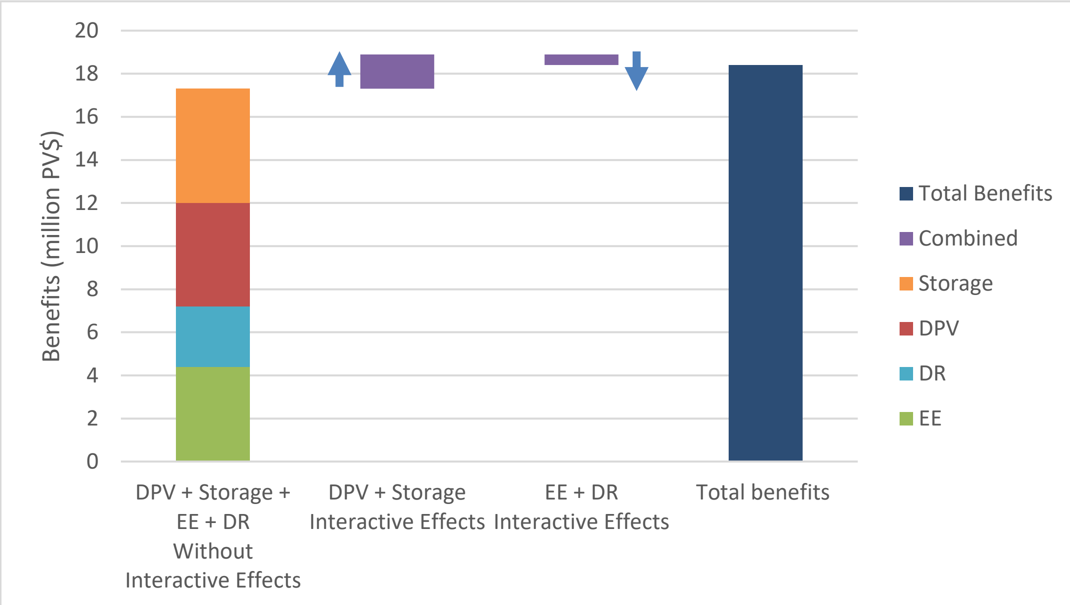
Multiple On-site DERs

Multiple on-site DERs can be installed in a variety of ways:

- On a residential level, utilities programs provide incentives to adopt multiple DER types that can then be used to benefit the customer and the grid.
- On a residential and commercial level, the aggregation of DERs in grid-interactive efficient buildings (GEBs) can provide grid support at scale.
- On a community level, DERs in microgrids and smart neighborhoods can be aggregated to provide grid support at scale.

The potential benefits and costs of multiple on-site DERs will depend on the type of DERs deployed, their capabilities, locational and temporal impacts, seasonal and daily load profiles, resource ownership and control of the DERs (i.e., level of dispatchability), and interactive effects across the DERs. Figure S-2 shows how the interactive effects between distributed photovoltaics and storage and between EE and DR can affect the total benefits of a GEB.

Figure S-2. Interactive Effects in Grid-Interactive Efficient Building



Non-Wires Solutions

These solutions focus on instances where utilities or others seek to install multiple DER types in a specific geographic area for the purpose of deferring or avoiding new investments in distribution or transmission systems. In these cases, cost-effectiveness will be very project-specific, depending on the specific transmission or distribution upgrade being deferred, the length of deferral, the mix of DERs producing the deferral, and a range of other factors. Due to the nature of T&D deferrals and uncertainty of load forecasts, NWS BCAs account for a project's number of years of deferral, which can shift depending on changing load forecasts.

Other key considerations for BCAs of NWSs include:

- When NWS projects are based on existing or new customer-sited DER programs, it is critical to accurately forecast customer participation and adoption, to reduce risk of not meeting requirements.
- Interactive effects should be accounted for, including effects on avoided costs, effects on kWh or kW impacts, and enabling effects.
- DERs geographically deployed to defer a T&D upgrade can have broader impacts on the utility system (e.g., avoided energy and generation capacity costs) as well as broader impacts related to policy objectives (e.g., avoided emissions).

<u>Illustrative Example of BCA for an NWS Project</u>

This manual provides an illustrative example of how a jurisdiction's primary test developed using NSPM can be applied to a hypothetical NWS project. The example assumes that a hypothetical state has developed its primary cost-effectiveness test (or modified its existing primary test) using the 5-step process described in Table S-2.

The state's JST accounts for conventional overarching goals of providing safe, reliable, resilient, and reasonably priced electricity services, as well as the goal of reducing GHG emissions (as articulated in statute). The JST also accounts for host customer impacts.

Non-Wires Solution Case Study Assumptions

In this example, an electric utility is facing the need to upgrade its system infrastructure due to distribution capacity constraints identified in a densely populated geographic area within its service territory. The utility proposes to integrate DERs to serve as a non-wires solution in place of an infrastructure upgrade.

The NWS plan includes the following BTM DERs in residential and commercial buildings:

- Energy efficiency measures (e.g., lighting and controls)
- Demand response (e.g., Wi-Fi-enabled thermostats)
- Distributed photovoltaics
- Distributed storage systems

Jurisdiction-Specific Test: The hypothetical jurisdiction's primary BCA test accounts for utility system, host customer, and GHG emission impacts.

Key assumptions:

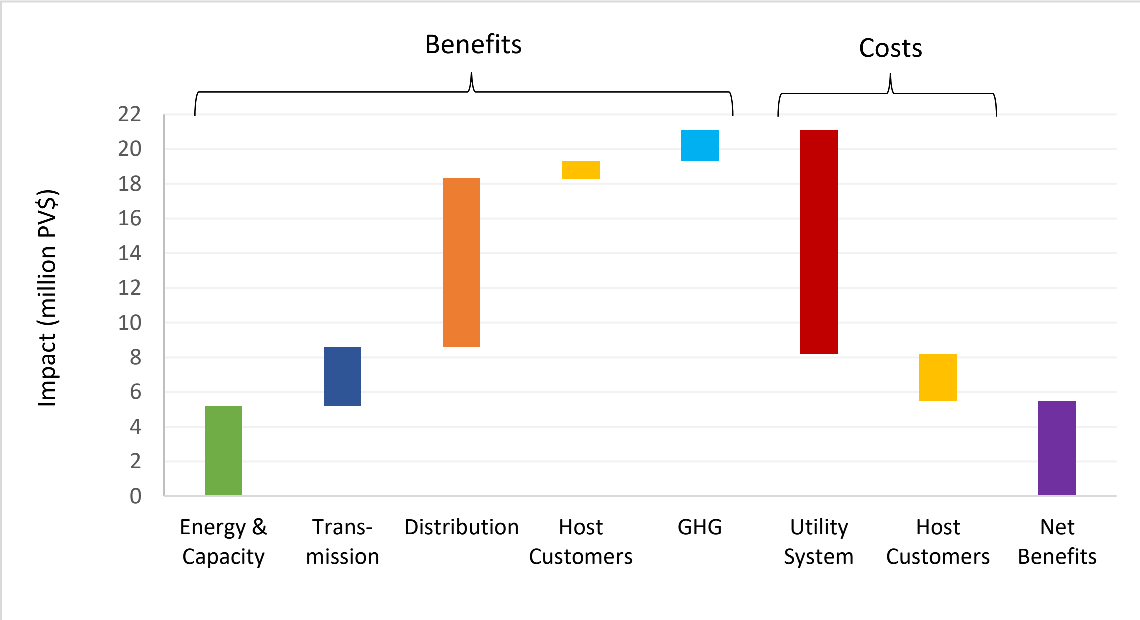
- *Non-Coincident Peak:* The distribution need is non-coincident with the overall system peak (e.g., the constrained distribution feeder peaks from 1:00–5:00pm, while system peaks from 5:00–9:00pm).
- *GHG Emissions Reduction:* The system-peak hours entail higher marginal emissions rates than the NWS, which allows the NWS to deliver GHG benefits.
- *DER Operating Profiles:* The NWS DERs operate in the following ways:
  - All DERs are operated to reduce the distribution peak, and some can reduce the system peak as well.
  - Storage charges during the distribution off-peak hours and discharges during the distribution peak hours.
  - DR reduces demand during distribution peak periods and/or shifts load from distribution peak periods to distribution off-peak periods.
  - Distributed PV resources generate during a portion of distribution peak period.
  - EE helps to reduce demand during distribution peak periods.

The example NWS benefits and costs associated with utility system, host customer, and GHG impacts are summarized below and presented in Figure S-3.

- *Generation Benefits* – Some generation benefits (e.g., energy generation, capacity, and ancillary services) accrue from targeting operation of DERs, such as storage and DR, during distribution peak periods. There will be additional benefits that result from some DERs—such as DPV and EE—also operating during other off-peak periods.
- *Transmission Benefits* – Some transmission benefits (e.g., capacity and system losses) accrue with the reduced delivery of central generation to customers.
- *Distribution Benefits* – The greatest contributor to the overall cost-effectiveness analysis is the direct benefit of operating DERs as much as possible during distribution peak periods.
- *GHG Benefits* – In this example, the GHG emissions are higher during the distribution system peak periods than the other periods. Consequently, the peak demand reductions from the NWS will result in a net reduction in GHG emissions.
- *General Utility Costs* – Financial incentives for customers to participate and administrative costs lead to the more substantive general utility costs for this illustrative analysis.
- *Host Customer Impacts* – Host customer costs include interconnection fees, transaction costs, and DER costs, while benefits include various non-energy impacts.

Figure S-3 combines the net benefits and costs of utility system, host customer, and GHG impacts. In this case study, locational value plays a central role in the cost-effectiveness of an NWS, as represented by the significant distribution benefits. The BCA indicates that the NWS will have net benefits.

Figure S-3. Illustrative Example of NWS Cost-Effectiveness



System-Wide DER Portfolios

The NSPM provides guidance on how to analyze and prioritize a portfolio of multiple DER types across a utility service territory.

In analyzing portfolios of multiple DER types across a utility service territory, it is important to first establish a single primary cost-effectiveness test that can be used for all DER types. Then, it is useful to articulate the jurisdiction's DER planning objectives, which can include, for example, one or some combination of: implement all cost-effective DERs; implement the lowest-cost DERs; maximize capacity benefits from DERs; encourage a diverse range of DER technologies; encourage customer equity; achieve GHG or electrification goals at lowest cost; and avoid unreasonable rate impacts.

Utilities and others can present the BCA results for DER portfolios in ways that facilitate comparison across DER types, such as:

- DERs can be ranked by benefit-cost ratios or net benefits to indicate the most cost-effective resources.
- Levelized DER costs can be used to directly and consistently compare costs across different DER types.
- Levelized net cost curves can be used to compare and prioritize DERs according to key parameters such as $/ton GHG reduced.
- Multiple cost-effectiveness tests, in addition to the JST, can provide additional information when analyzing portfolios of multiple DER types.

Figure S-4. Example DERs Sorted by Net Benefit

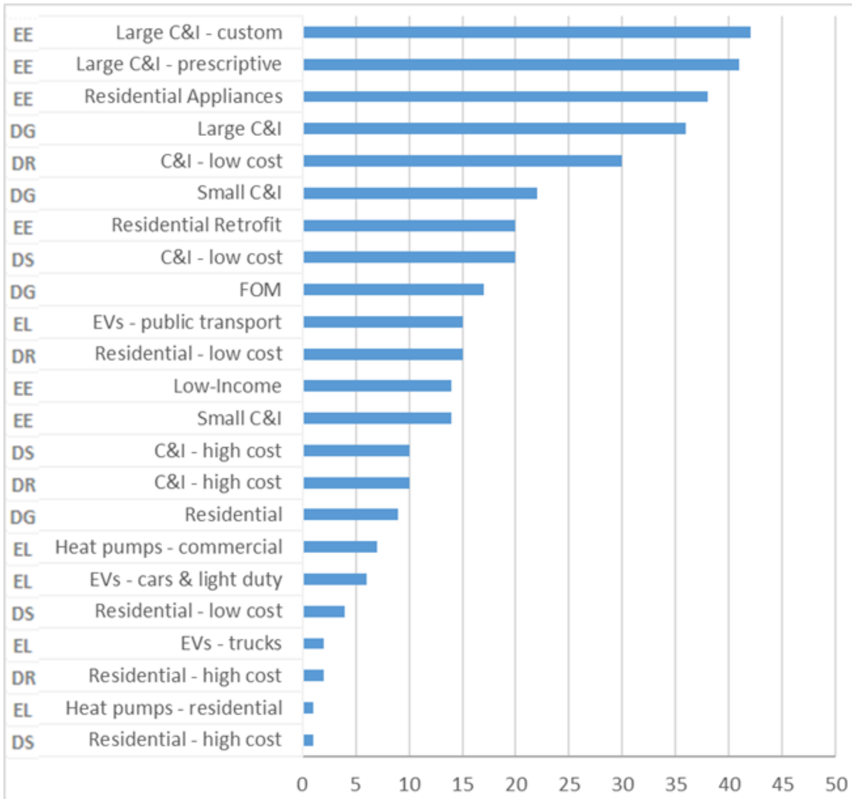


Figure S-4 presents a list of hypothetical DERS sorted by the net benefits that they provide. This information could be used to identify those DERs that warrant utility support or funding in order to achieve the greatest net benefits for a given level of funding. A similar approach could be used to prioritize BCRs by their benefit-cost ratios, or to prioritize DERs for within a given rate impact cap.

In some cases, a jurisdiction may prefer to invest in a diverse range of DER types on the basis that all DER types contribute benefits in different ways and there is value in promoting a diversity of technologies, as well as reducing associated system risk. In such a case, regulators might decide to support a minimum amount of each type of DER. This could be achieved by sorting the DER types by net benefits or benefit-cost ratios and selecting the lowest cost options for each type of DER.

Dynamic System Planning

Utilities have conducted traditional distribution system planning for many years to determine how to best to build and maintain the distribution grid. The focus of this practice has been on providing safe, reliable power through the distribution grid at a low cost. It typically has not accounted for DERs as alternatives to traditional distribution system technologies. However, the scope of utility system planning is expanding to manage the increasing complexity of the electricity system, while addressing evolving state policy objectives, changing customer priorities, and increased DER deployment. The manual provides an overview of evolving advanced planning practices that can allow utilities to more effectively and dynamically optimize DERs using *dynamic system planning*.

Table S-9 summarizes several different types of planning practices used by electric and gas utilities. It presents practices according to whether they are used by distribution-only or vertically integrated utilities, and it shows what elements of the utility system are accounted for by each type of practice.

Each type of planning practice uses some form of BCA for comparing and optimizing different resources. Each practice is a type of dynamic system planning described above, where the resources of interest are optimized relative to a dynamic set of alternative resources.

Table S-9. Types of Dynamic System Planning Practices

Type of Utility System	Planning Practice	Planning Practice Accounts for: Distribution System	DERs	Transmission System	Utility-Scale Generation
Distribution-only & vertically integrated	Traditional distribution planning	✓	-	-	-
	Integrated distribution planning (IDP)	✓	✓	-	-
Vertically integrated	Transmission planning	-	-	✓	-
	Integrated resource planning (IRP)	-	✓	-	✓
	Integrated grid planning (IRP)	✓	✓	✓	✓

Dynamic system planning practices have evolved in recent years to optimize DERs and maximize their value to the system. These include integrated distribution planning (IDP) for distribution-level planning only and integrated grid planning (IGP) for full-system planning.

Appendices

Table S-10 summarizes the appendices that provide further detail on some NSPM topics that warrant additional explanation.

Table S-10. Guide to Appendices

Part V	Appendices	
Appendix A	Rate Impacts	Describes the difference between cost-effectiveness and rate impact analyses, as well as the role of rate, bill, and participation analyses
Appendix B	Template NSPM Tables	Tables that can be used by jurisdictions to document applicable policies and relevant benefits and costs to inform their BCAs
Appendix C	Approaches to Accounting for Relevant Impacts	Provides guidance on options to account for relevant benefits and costs, including hard-to-quantify impacts and non-monetary impacts
Appendix D	Presenting BCA Results	Provides guidance on presenting results in a way that is most useful for making cost-effectiveness decisions
Appendix E	Traditional Cost-Effectiveness Tests	Summarizes the commonly used traditional cost-effectiveness tests from the *California Standard Practice Manual*
Appendix F	Transfer Payments and Offsetting Impacts	Provides guidance on impacts that appear to be both a benefit to one party and a cost to another party, thereby cancelling each other out
Appendix G	Discount Rates	Describes ways to determine discount rates that are consistent with the jurisdiction's applicable policy goals
Appendix H	Energy Efficiency—Additional Guidance	Describes how to address free-riders and spillover effects where net savings are used; and treatment of early replacement measures

The SOLAR FOUNDATION™
for a bright future

ARIZONA

SOLAR JOBS CENSUS 2019

There are 249,983 Americans working in solar as of 2019, according to The Solar Foundation's latest *National Solar Jobs Census*. Visit SolarStates.org for details on solar jobs in all 50 states, the District of Columbia, and Puerto Rico.

Sunny Arizona is one of the top states in the nation for solar employment. The state has an abundant solar resource and enormous potential for growth.

STATE SOLAR JOBS: 7,777

6 — **STATE RANKING** FOR SOLAR JOBS

9 — **STATE RANKING** FOR SOLAR JOBS PER CAPITA

- **253** — New Solar Jobs, 2019
- **3.4%** — Solar Jobs Growth, 2019
- **15** — State Rank by Net Solar Jobs Added, 2019
- **6.1%** — Projected Jobs Growth, 2020
- **9%** — Percentage of State Solar Workers Who Are **Veterans**

SOLAR JOBS BY SECTOR

INSTALLATION
3,747
(11% increase)

MANUFACTURING
2,473
(3% decrease)

WHOLESALE TRADE & DISTRIBUTION
702
(2% increase)

OPERATIONS & MAINTENANCE
483
(3% decrease)

OTHER
373
(8% decrease)

SOLAR INDUSTRY CONTEXT

4,646 MW
CUMULATIVE INSTALLED SOLAR CAPACITY[1]

3 — **STATE RANKING** FOR INSTALLED SOLAR CAPACITY[1]

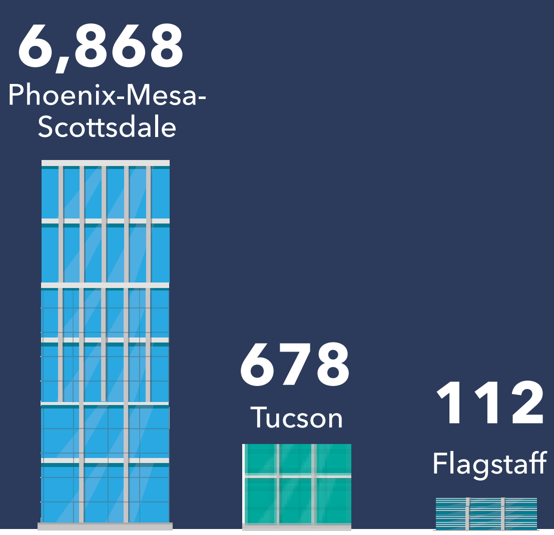
ENOUGH SOLAR TO POWER **778,421** HOMES[1]

473
Solar Companies[2]

6.63%
of State's Electricity Generation from Solar[3]

Learn more at SolarStates.org

TOP METROPOLITAN STATISTICAL AREAS FOR SOLAR JOBS



DID YOU KNOW?

In February 2019, Arizona Public Service announced it will add 850 MW of battery storage and at least 100 MW of solar generation by 2025.[4]

ARIZONA

SOLAR POLICY CONTEXT

D

Net Metering Policy Grade[5]

F

Interconnection Policy Grade[5]

Solar installations sized to meet up to 125% of a customer's electric load receive compensation for solar sent back to the grid credited at the Resource Comparison Proxy export rate which is based on the cost of energy from utility-scale solar farms over a five-year period. The rates are reset annually but do not decrease more than 10% for any given year. There is no limit to the number of systems covered.

RENEWABLE PORTFOLIO STANDARD[9]

15%

by 2025

RENEWABLE PORTFOLIO STANDARD CARVEOUTS[9]

4.5%

Distributed Generation

COMMUNITY SOLAR PROGRAM GRADE[7]

N/A

COMMUNITY CHOICE AGGREGATION STATUS[8]

CCA not available

LEGAL STATUS OF THIRD PARTY OWNERSHIP[9]

Authorized by state, but limited to certain sectors

PROPERTY ASSESSED CLEAN ENERGY FINANCING (PACE) STATUS[10]

N/A

STATE INSTALLER LICENSING REQUIREMENTS[6]

Electrician's License

30%

Employers Reporting It Was "Very Difficult" to Hire Qualified Employees

16

STATE RANKING FOR AVERAGE ELECTRICITY PRICE[3]
(Highest to Lowest)

10.85
CENTS/KWh

AVERAGE ELECTRICITY PRICE[3]

1 Wood Mackenzie, Limited and the Solar Energy Industries Association (SEIA), *U.S. Solar Market Insight*
2 SEIA, National Solar Database
3 U.S. Energy Information Administration
4 https://www.greentechmedia.com/articles/read/aps-battery-storage-solar-2025
5 Based on Freeing the Grid 2015, Vote Solar, Interstate Renewable Energy Council (IREC), and EQ Research. Grades updated by The Solar Foundation
6 IREC, *National Solar Licensing Map*
7 IREC, *2019 National Shared Renewables Scorecard*
8 Local Energy Aggregation Network, https://leanenergyus.org/cca-by-state/
9 North Carolina Clean Technology Center at North Carolina State University, *Database of State Incentives for Renewables and Efficiency*
10 PACENation, available at pacenation.us/pace-programs/

The True Value of Solar

Measuring the Benefits of Rooftop Solar Power

ENVIRONMENT AMERICA
RESEARCH & POLICY CENTER

FRONTIER GROUP

Table of Contents

Executive Summary

Distributed solar energy is on the rise, generating enough electricity to power more than 6 million homes each year, and resulting in annual carbon dioxide emission reductions equivalent to taking 4.4 million passenger vehicles off the road.[1] Public policy has been a key factor in driving the growth of solar energy – recognizing the enormous benefits that solar power can provide both today and in the future.

To help develop smart public policy around solar energy, many public utilities commissions, utilities and other organizations have conducted or sponsored "value-of-solar" studies that attempt to quantify the monetary value of the benefits delivered, and costs imposed, by the addition of solar energy to the electric grid. Studies that include a full range of solar energy's benefits – including benefits to the environment and society – reliably conclude that the value of

Figure ES-1. The Benefits of Rooftop Solar Energy[2]

Benefit Category		Benefit
Grid	Energy	Avoided electricity generation
		Reduced line losses
		Market price response
	Capacity and Grid Investments	Avoided capacity investment
		Avoided transmission and distribution investment
		Reduced need for grid support services
	Risk and Reliability Benefits	Reduced exposure to price volatility
		Improved grid resiliency and reliability
	Compliance	Reduced environmental compliance costs
Societal	Environment	Avoided greenhouse gas emissions
		Avoided air pollution
		Health benefits
		Avoided fossil fuel lifecycle costs
	Economy	Local jobs and businesses

those benefits approximates or exceeds the compensation solar panel owners receive through policies such as net metering.

Many value-of-solar studies, however – especially those conducted by electric utilities – have left out key benefits of solar energy. Policymakers and members of the public who consult these studies may be left with a false impression of solar energy's value to the grid and society, with damaging results for public policy.

To make decisions that serve the public interest, policymakers should account for the full value of solar energy, including societal benefits to the environment and public health.

Rooftop solar energy brings a wide variety of benefits to the grid and to society.

- Rooftop solar power generally adds value to the electric grid. It not only reduces the need for generation from and investment in central power plants, but over the long lifetime of solar energy systems it also can increase price stability and grid reliability, and reduce environmental compliance costs.

- As a clean, emission-free energy source often located on private property and built with considerable private, non-ratepayer investment, rooftop solar brings valuable societal benefits. Solar energy reduces global warming pollution, and also reduces emissions of dangerous air pollutants such as nitrogen oxides, mercury and particulate matter.

Value-of-solar studies inconsistently account for solar energy's benefits, especially beyond the electric grid, resulting in dramatically different conclusions.

- Studies that include the benefits of solar energy beyond the grid generally find that its value exceeds the retail rate of electricity. Recent studies from states including Maine, Pennsylvania and Arkansas have found that solar energy brings substantial environmental benefits, and that rooftop solar owners would provide a net benefit to society even with net metering compensation.[3]

- Studies commissioned by electric utilities generally fail to account for benefits beyond the grid, resulting in far lower values of solar. A 2016 report published by Environment America Research and Policy Center and Frontier Group reviewed value-of-solar studies and found that, of 16 studies reviewed, only eight accounted for avoided greenhouse gas emissions, and no studies commissioned by utilities accounted for the value of solar energy beyond the grid. The studies that left out societal benefits valued solar, on average, at 14.3 cents per kilowatt-hour, compared to 22.9 cents for those studies that at least accounted for greenhouse gas emissions.

Value-of-solar studies should account for all of solar energy's benefits to the grid and society.

- Policymakers must account for the societal value of reduced power plant emissions, in particular the value of avoided greenhouse gas emissions and pollutants that contribute to the formation of smog and soot.

- Policymakers should also seek to account for broader societal impacts of solar energy, including "upstream" impacts of fossil fuel production and use, such as methane emissions from fracking, and local economic development impacts.

Public policy that fails to account for the full range of benefits may deter the addition of solar power to the grid, with ramifications for the environment, public health, and the operation of the electric grid.

NREL Transforming ENERGY

Community Solar 101

National Renewable Energy Laboratory

Jenny Heeter
Kaifeng Xu
Emily Fekete

Community Solar is Defined as...

Community solar, also known as *shared solar* or *solar gardens,* is a distributed solar energy deployment model that allows customers to buy or lease part of a larger, offsite shared solar photovoltaic (PV) system and receive benefits of their participation.

Other definitions include:

- A solar power plant whose electricity is shared by more than one property
- Community-owned projects as well as third party-owned plants whose electricity is shared by a community.

“Community Solar: What Is It?” EnergySage, January 16, 2020. https://www.energysage.com/solar/community-solar/community-solar-power-explained/.

Community Solar Structure Design

Three Common Business Models

Utility-led: Orlando Utility Commission

- 400 kW PV Project
- OUC buys the electricity at $0.18/kWh under a PPA from private solar developer
- Subscriptions: 1 to 15 kW
- Cost: $0.13/kWh

  (avg. $14.56/month per kW)
- Solar rate roughly $0.015-0.025/kWh more than retail rates but fixed for up to 25 years
- $50 up-front fee
- 2-year minimum participation.

http://www.ouc.com/environment-community/solar/community-solar/community-solar-faq#cost

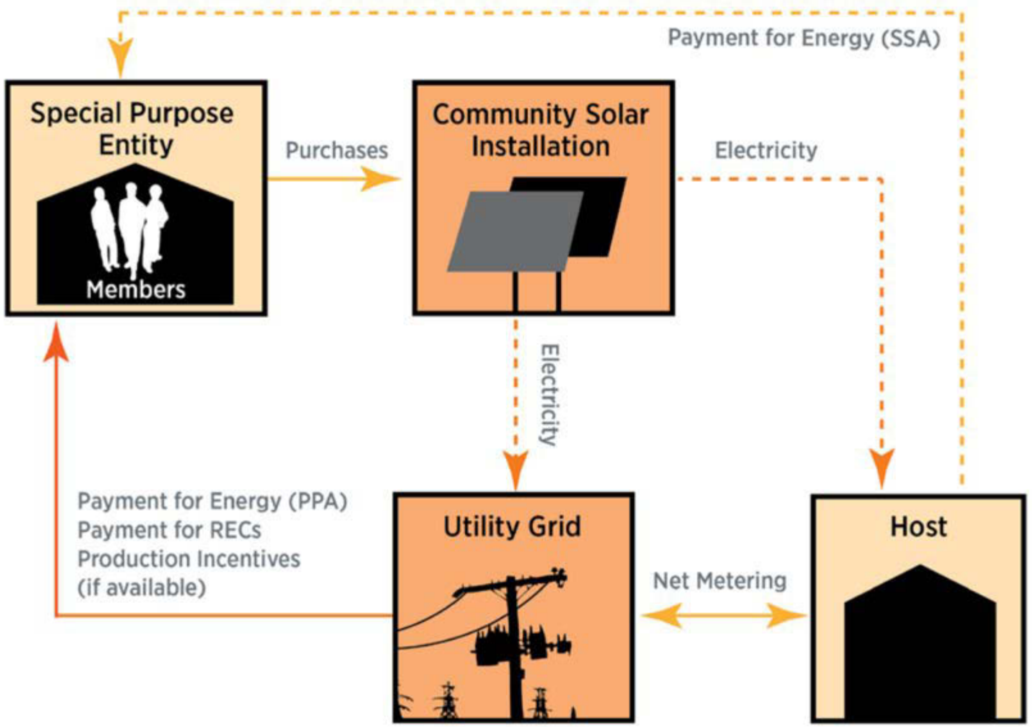
Third-party Led:
Clean Energy Collective

- Origins in Colorado but expanding to MA, NY, and other states
- Currently, there are 110 community solar projects within 33 utility service territories across 11 states.

https://www.communitysolarplatform.com/

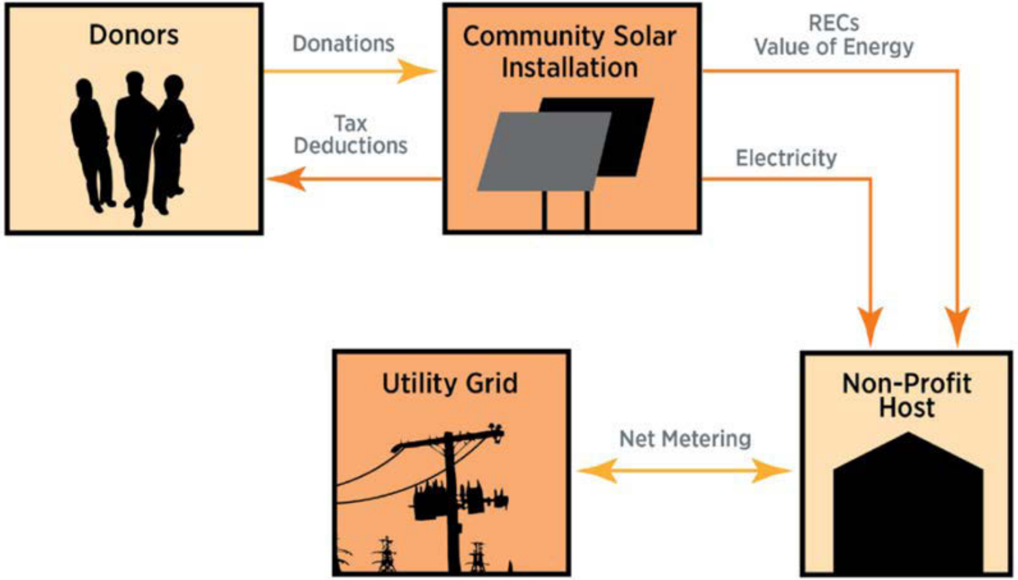
Special Purpose Entity Model

- In some cases, in order to fully use the investment tax credit (ITC), organizations form a Special Purpose Entity (SPE) as the owner of community solar project
- Customers still receive credit reflected on their utility bills.

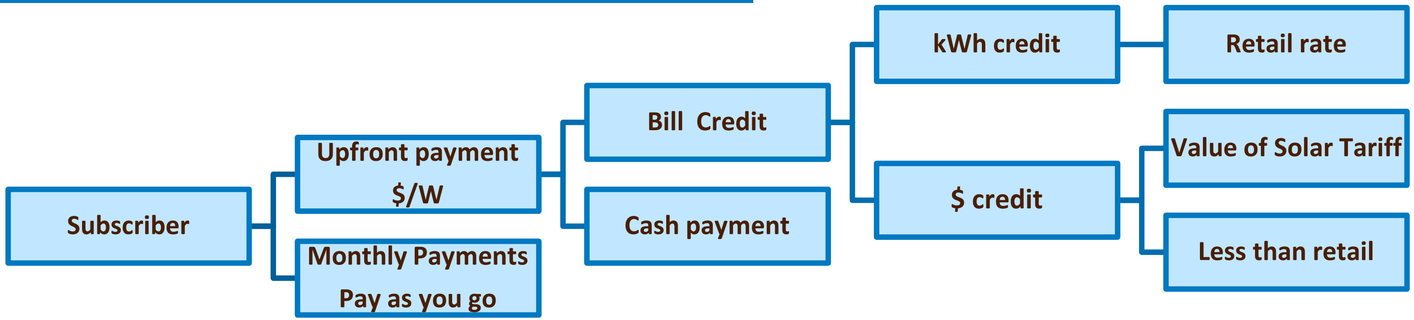


Nonprofit Donation-Based Model

- In nonprofit model, community solar system will be paid for by donors who do not receive benefits from the electricity generation
- The solar system is typically sited on a nonprofit or government building, adding to the “community” nature of the project.



Subscriber Perspective



Typical subscriber questions

- What if I move within utility district?
- What if I leave the state?
- How long do I have to be a member?
- What’s my payback?
- Do I get a tax credit?
- Do I own my panels?
- Will I save money?

CEC: Vermont

Community Solar for Low- and Moderate-Income (LMI) customers

Defining LMI

- LMI refers to “low-income” or “low-to-moderate income” populations, which is generally determined as a percentage of area median income (AMI)
- The U.S. Department of Housing and Urban Development defines very low income as 50% of AMI and low-income as 80% of AMI
- Both low-income and LMI populations face challenges with respect to solar access they are often considered together.

What is LMI Community Solar?

- LMI community solar refers to community solar projects that are inclusive of or incentivize LMI participants
- These projects can include specific LMI carve outs or other incentives to generate LMI participation.

Why is LMI Community Solar Important?

- LMI households have the most to gain because electricity costs make up a larger fraction of their budgets compared to more affluent households
- LMI customers face more obstacles to obtaining solar energy such as lower credit scores and insufficient tax burden to be eligible for state and federal solar tax incentives
- Historical business models required home ownership, a suitable roof, and good credit ratings, while much of the LMI community are renters living in multifamily units with limited access to capital.

“National Community Solar Partnership (FY2016).” Energy.gov. U.S. Department of Energy. https://www.energy.gov/eere/solar/national-community-solar-partnership-fy2016.

Just & Equitable Transition for Coal-Impacted Communities

Just and Equitable Transition for Coal-Impacted Communities

10 Requirements for Mitigating Power Plant and Mine Closures and Rebuilding Post-Coal Economies

What is a Just and Equitable Transition?

Just and Equitable Transition, as it relates to the energy sector, is the concept that the companies owning and operating power plants and coal mines, many of which are the economic backbones of the communities they are situated in, have a corporate responsibility and ethical obligation to provide financial support when they make plans to close down facilities and to assist these communities in developing post-coal economies.

Especially in the West, power plants and mines are often the largest employers in a community, and they serve as one of the largest sources of municipal, county and tribal tax revenue, providing core funding for things like emergency and social services and school districts. When plants and mines are shuttered abruptly, the economic disruptions are painful, resulting most directly in heavy job losses and precipitous drops in tax revenue. The ripple effects don't stop there, though. Because prosperity is so directly linked to plant and mine operations, closures force a longer-term economic reckoning about the kinds of businesses and industries that will help communities survive beyond coal. That kind of rebuilding cannot happen overnight. It requires years of planning.

In a Just and Equitable Transition, utilities and mining companies are held accountable to communities that gave so much in the name of supplying inexpensive electricity to ratepayers and profits to shareholders. A Just and Equitable Transition means communities that are economically dependent on coal are not left behind as power plants and mines close while the world shifts to cleaner energy sources. It means that those who have suffered the direct environmental and health impacts of nearby mining and coal combustion are compensated in ways that lead to basic improvements in their standard of living. And it means utilities and mining companies must assist communities through financial and technical assistance in their transition to new modes of post-coal economic development.

"For decades, the Navajo Nation has been host to coal-fired power plants, including the Navajo Generating Station, that provided inexpensive power to residents of Phoenix and Tucson ... [A]s the state's utilities begin to pivot their energy portfolios away from coal, the Navajo Nation is faced with significant economic repercussions."

— Navajo President Jonathan Nez in comments submitted to the ACC requesting utility transition support

Why is Just and Equitable Transition important now?

There are seismic economic shifts reshaping the way we get our electricity, in Arizona and across the nation. In most instances, it is now cheaper to build new wind, solar and energy storage projects than it is to keep operating existing coal plants. As a result, utilities are having to completely rethink their business models and adjust their resource planning. For many, that means closing down plants that are no longer competitive, often decades earlier than anticipated – with the mines that supply them soon to follow. The impact is impossible to ignore. In 2010, coal generated more than 50% of the electricity in the United States. This year, coal's share of power generation will fall below 20% as it is swiftly displaced by lower cost renewables and fracked gas. In Arizona, just in the last year, the state's biggest utilities have dramatically accelerated the retirement dates for some of the biggest power plants in the West.

- Navajo Generating Station, the single largest coal-burning plant in the West, co-owned by Arizona Public Service (APS), Tucson Electric Power (TEP) and Salt River Project (SRP), was closed in November, more than two decades ahead of schedule and with less than three years' notice.
- The closure date for San Juan Generating Station, owned partly by TEP, was moved up by almost three decades.
- APS moved up the closure date for its Four Corners Power Plant by seven years to 2031, and the economics indicate it could close even earlier. APS also announced it will completely close its Cholla Power Plant years early.
- TEP has decided to shut down the two units it owns at the Springerville power plant in 2027 and 2032, more than a decade ahead of schedule.
- And SRP is now exiting its ownership stake in units at power plants in Colorado years earlier than planned.

Such swift and large-scale change does not come without fallout, and in the case of coal-fired power, it is the people, communities and businesses built around coal that most acutely feel the consequences of boardroom decisions to shut down power plants and mines. These early closures – usually foisted upon communities with little notice, planning or support – are like having the rug pulled out from under them. Yet, to date, Arizona's utilities have done next to nothing to help mitigate the impact on communities.

What are the core elements of a Just and Equitable Transition?

For a Just and Equitable Transition to provide adequate support for communities to both weather the immediate disruption of a plant or mine closure and plan for a better future, utilities and mining companies must commit to assistance and planning with the following features, at minimum:

1. **Transparency and advance notice.** Just and Equitable Transition starts long before retirement decisions are made. Utilities and mining companies must be up front with the communities they operate in about today's changing economic realities and transparent about their plans. It is critical for stakeholders to be informed with adequate advance notice – measured in years – that will allow them to begin planning for the economic shock that comes with plant and mine closures and for building the economic future that will come afterward.

2. **Community equity in the transition process.** The people, businesses, organizations, and agencies that are most affected by plant closures, and who know their own communities most intimately, must be at the forefront of decision-making for any economic transition.

3. **Re-employment, job/skills training, and education.** Plant and mine workers will be the most directly and immediately impacted by closure decisions, and utilities and mining companies have an obligation to their workforces to provide access to skills training and re-employment opportunities.

4. **Community financial support/assistance.** One of the most far-reaching and long-term consequences of a plant or mine closure is lost revenue to local and tribal governments and school districts. Utilities must provide funding dedicated to cushioning the blow to budgets for impacted government services.

5. **Local development of replacement energy and transmission projects.** As utilities remove fossil fuel capacity from their portfolios, they are looking to replace it with energy efficiency, storage, and renewable energy resources. One of the main ways that utilities can and should provide transition support is through commitments to develop and partner on new clean energy projects near retired facilities, thus creating fair wage jobs, new career opportunities and replacement sources of tax revenue.

6. **Economic redevelopment and diversification assistance.** Reinventing a local economy, even a small one, cannot happen overnight. The planning that goes into such a complex process and the scope of the stakeholders involved is diverse and may include local business and industry representatives, organized labor, advocates, educators, elected officials, regional economic development agencies, clean energy developers and academics, not to mention the utilities themselves. Convening an inclusive process to bring all these voices together with the aim of attracting new business and development will require dedicated funding and participation.

7. **Decommissioning, remediation, and reclamation activity.** While power plants and mines create jobs and tax revenue, they also have disproportionate harmful impacts on land, air and public health, both on site and in surrounding communities. Power plants and mines also consume massive amounts of water. A Just and Equitable Transition requires appropriate funding to right environmental damages and to develop plans for freed up water.

8. **Local hiring preferences.** Whether it is development of new clean energy projects or cleanup of existing facilities, closures create potential for hundreds of jobs with work spanning several years. It may be financially expedient for companies to bring in itinerant workforces for these jobs, but a Just and Equitable Transition demands that hiring preferences be given to local workers most directly impacted by closure decisions.

9. **Access to electricity and water.** Especially in the case of tribal communities, the long-promised economic benefits of allowing mines and power plants to be sited on their land never materialized. For example, four of the biggest power plants in the West are situated on or near the Navajo Nation, yet nearly a third of the tribe's households lack access to electricity or running water. Utilities should atone for this embarrassing injustice by including funding to help bring power and water to these homes as part of their transition commitments.

10. **Participation.** It is not sufficient for power and mining companies to simply write a check to fund "transition" activities. A Just and Equitable Transition demands a constructive conversation and systematic process to determine how financial support and technical assistance can and should be used most effectively. Because utilities and mining companies have been a part of community fabric for so long, it is incumbent on them to continue their participation as key stakeholders in an inclusive transition planning process.

Finally, it is worth emphasizing that, to date, while the preceding elements are vitally important to assisting communities in their transition to life after coal, utilities have so far fallen woefully short of meeting any of these criteria. Rather, their preferred retirement MO is to close up shop and lock the gates behind them with little notice, leaving communities to grapple with the harsh economic realities themselves. Corporate executives have been reluctant to even bring up the idea of providing support for a Just and Equitable Transition, let alone fund it, which is why it's so important for energy policy-makers to take up the mantle of protecting these communities by ensuring they have an opportunity to create a prosperous future.

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Why is Just and Equitable Transition important now?

NAVAJO GENERATING STATION /

KAYENTA MINE

Closure – November 2019, 25 years earlier than scheduled

Location – Navajo Nation, near Page, AZ

Workforce – 500 at NGS, 265 at the mine, 90% Navajo and Hopi

SAN JUAN GENERATING STATION

SAN JUAN MINE

Closure – Two units closed in 2017, two more will close in 2022, three decades earlier than scheduled.

Location – Near Farmington, N.M, just south of the Navajo Nation

Workforce: 400 at SJGS, 500 at the mine, 50% Navajo

FOUR CORNERS POWER PLANT /

NAVAJO MINE

Closure – Three units closed in 2013. Remaining two will close in 2031, seven years ahead of schedule and possibly sooner.

Location – Navajo Nation near Farmington, N.M.

Workforce – 500 at the plant, 500 at the mine, 80% Navajo

CHOLLA POWER PLANT

Closure – One unit closed in 2016, another closing this year and the shut down of the last two units in 2025, years early.

Location – Joseph City, AZ, just south of the Navajo Nation

Workforce – 200

4 power plants, 3 mines, 2,800 workers, tens of millions in lost annual tax revenue, decades early …
And to date, $0 committed by utilities and mine operators to community transition.

JUST TRANSITION FUND

How to Get Started

A Guide to Help Local Governments Engage on Coal Transition

A national energy transition is sweeping the country—and many communities are feeling the effects as coal mines are closing and coal-fired power plants are replaced by natural gas and renewable sources of electrification. In many of these communities, coal-fired plants are primary drivers of the local economy. When those plants or mines close, significant economic distress results. Workers lose jobs. Some move away. The tax base erodes and tax revenues decline, causing budget cuts to schools, health care, and other public sector services.

In the face of such upheaval, local government officials must chart a difficult path forward, and many are left wondering where to start. Some governments become paralyzed with uncertainty. Other recognize the need to plan and take action. Although transitioning away from coal can be challenging, it's far from impossible.

The Just Transition Fund has provided direct technical assistance to dozens of communities struggling with transition. Through that work, we've gathered a wealth of experience, guidance, suggestions, and ideas on how to start a transition planning process. We know from first-hand experience that early planning is critical for sustainable and meaningful community transition, and we've created this resource to help local leaders do just that.

Six Steps to Get Started

We've divided the transition process into six steps, each building on the one before. As you move through them, remember that planning is an iterative process; as local leaders learn, they will likely decide to make adjustments that best meet the needs and opportunities in their communities.

The six core steps toward beginning a responsible transition include:

Engage Early

The sooner you start exploring your options, the more time you'll have to make them a reality before a plant or mine closure can deliver a serious blow.

Engage Diverse Stakeholder Perspectives

Not everyone will have the same views about what can or should be done in shaping your community's future. Welcome, listen carefully to, and learn from diverse stakeholder perspectives.

Find Out the Facts

Learn exactly what the impact of a mine or plant closure will be in your community, and take a look at the assets you can leverage as you make your transition.

Find Funding

It's out there. Learn where to look, and where to ask for help in finding it.

Bring the Community Together

Work together to create the future. Ensure that all voices are heard and included in decision making about your community's future, especially those who may have been marginalized or left out of the coal-based economy.

Plan for the Long Term

A new community vision will take time to achieve. Keep an eye on that longer horizon, even in the face of pressing immediate needs.

ENGAGE EARLY

Even in locations where it seems unlikely that a coal plant will be affected in the near term by the energy shift, it's best to engage with elected officials and other community members sooner rather than later in discussing closure possibilities. Plants that operate at high capacity can face the same risk of closure or other operational changes as lower-capacity plants due to the possibility of a company's restructuring or integrated resource planning. Some of the most successful transition leaders began "what if" conversations about plant or mine closures well before those closures became a reality. They rallied others around the work of planning the future, rather than constantly looking to the past or becoming mired in the present.

Early engagement depends 100% on leadership. You'll need to identify a leadership team that can lead you through all of the steps of transition: gathering facts, engaging community, visioning and planning for the future, and finding funding.

Characteristics to consider as you identify members of your transition team

- Have local and regional economic knowledge
- Are considered unbiased
- Have influence in the public, private, and nonprofit sectors
- Have expert knowledge, connections, or are those known for visionary thinking or creativity
- The more diverse your transition team, the more sustainable your plan ultimately will be.

Potential transition team members*

- Representatives of the utility and owners of the site
- Individuals from government
- Individuals from labor
- Community members
- People from academia
- Tribal communities
- Non-profit or faith-based organizations
- Philanthropic groups
- Issue experts (e.g., school finance practitioners, local taxation and finance managers, realtors, community planners, union leaders, and economic development professionals)

**Note: Not every team member has to be involved in the entire process. Some may best contribute by concentrating their time and expertise in certain segments.*

A list of questions to consider in Step 1 is included at the end of this guide.

FIND OUT THE FACTS

Losing a major industry is a blow to any community. Those impacts are magnified when rumors or inaccuracies prevail. Transitions that succeed are the ones that are rooted in facts—not emotion, assumptions, or rumors. When you know the facts, you can plan for the future with more certainty.

Dig into actual job loss figures, as well as the likely impacts on housing, taxes, debt retirement, and secondary services such as health care and schools. You'll likely need to learn more about specific aspects of taxation, public finance, workforce retraining, or other issues your team identifies as important during your process. Community transition is an ongoing and iterative process, and so is the need for information gathering.

In particular, finding the facts can help you **1) define the problem**, and **2) existing assets** in your community.

1. Define the Problem

The following questions can help you think more deeply about the potential impacts of a plant or mine closure in your community, and guide your search for information. Be honest about what you still need to know, and don't hesitate to ask leaders in your community, in the state, or at federal agencies how you might obtain the information or connect to expert resources.

- Where do tax dollars originate currently and how they are spent?
- Are there state or federal matching funds at risk if your community can no longer provide its share?
- What's the value of the nonfinancial support the community gets from the utility or mine in question?
- How might the social and cultural fabric of the community change?
- What are the properties and structures the mine or utility will leave behind after closure?
- What will a closure do to your community's infrastructure?

2. Existing Assets

Even if the mine or power plant is the biggest game in town, it isn't the only game in town. Take an inventory of your community's assets. They may not be obvious at first, and some assets require a broader understanding of economic value. Community assets might include:

- Developed land (public or private, including the site of the closing mine or power plant)
- Infrastructure (roads, rail lines, well heads, water and sewer lines, power lines, etc.)
- Undeveloped land (such as scenic areas that could attract outdoor recreation)
- Water (underground or aboveground, for industrial or recreational use)
- Entrepreneurs (who own or might start small or medium-sized businesses)
- Artists/craftspeople (those who create and inspire)
- Culture (that which defines your community)
- Connections (to resources and knowledge beyond your community that can inform or support your work)

A list of questions to consider in Step 2 is included at the end of this guide.

BRING THE COMMUNITY TOGETHER

A plant or mine closure will affect almost everyone in your community. In some cases the impact will be obvious; in others, less so. Likewise, the direct impacts of a closure will almost certainly spawn secondary or indirect impacts that will expand in a ripple effect through your community. You and your team will want to spend some time identifying, documenting, and verifying the potential impacts to your community.

Direct impacts include loss of property and tax revenue, loss of jobs at the plant and any local associated mines, and legacy cleanup and remediation costs of coal-related operations. Unanticipated direct impacts may include reduced local government bond ratings, which make financing capital improvements difficult. Likewise, as a local government's ability to provide services decreases due to lower tax revenue, municipal insurance rates may rise.

Secondary or indirect impacts may include gaps in the industrial and commercial supply chain of products and services; loss of housing value and higher vacancy rates; declining revenue for a host of local businesses such as retail stores, day care services, personal services, medical services, or transportation networks; and infrastructure that may become idle or oversized.

You'll want to be sure to engage the full spectrum of those affected by closure—directly or indirectly—in a community engagement process. Community engagement is critical, because it not only allows transition leadership to hear and understand concerns, but also provides fertile ground for creativity and new ideas, and ultimately helps those in the community feel a sense of ownership in the transition planning and implementation.

Design an Inclusive Engagement Process

Transition planning is messy work. Members of your community may have widely different ideas about what they want to see and what priorities should be for the future. How do you keep the process moving forward? Here are six ground rules for keeping the engagement productive.

1. **Honor the past:** Provide opportunities to acknowledge the generations of workers who have been employed and the importance that the mine or plant has played in the community.
2. **Use respected, neutral facilitators to create a safe space:** Find people and groups who have influence and are respected in the community and who can help conversations be positive and forward-thinking.
3. **Make discussions accessible:** Hold facilitated discussions at various times of day to accommodate participants' schedules, and bring the listening process to locations people can easily reach.
4. **Acknowledge dissent, but avoid blame and denial:** Dissent is common, but a skilled facilitator or leader can manage it constructively to inform, rather than wreck, a productive conversation.
5. **Stick to the facts.** Present the facts and impacts as you know them, provide resources to address unanswered questions, and set the stage for constructive input from the community.
6. **Set clear goals.** Use the initial facts you've gathered and the public opinions you've heard to draft a set of goals for your transition process. Then, ensure that your community stakeholders can agree on those goals, or encourage them to draft goals together.

A list of questions to consider in Step 3 is included at the end of this guide.

ENGAGE DIVERSE STAKEHOLDER PERSPECTIVES

Various groups in your community will feel the weight and possibilities of transition very differently. Gather, respect, and examine all perspectives to ensure that you create a long-term transition plan that all community stakeholders can support.

Below, we've identified ten different stakeholder groups and some of their concerns and ideas about transition. However, this list is by no means comprehensive, and every community is different. Use these ideas as a starting point, then add more stakeholder segments that are relevant to your community.

Common Stakeholders in Community Transition

Power Generation and Distribution Companies

Although in some cases a closure may create tension between these stakeholders and others, they can bring important resources to the conversation and a willingness to be productive contributors to community.

Municipal Leaders

Elected officials and other government employees bring a deep knowledge of tax and public funding issues, and may feel the added pressure of sustaining public services in the face of diminishing revenue.

Labor & Trade Unions

Workers who lose jobs as a result of the closure will be able to share immediate impacts and provide valuable information about what they would like to see next.

Environmental Groups

Input from these groups can both help communities address legacy environmental issues around a closed plant or mine and protect natural areas and understand how to best leverage them for recreation or other purposes.

Community Leaders

Those who lead your community's nonprofit organizations, religious organizations, clubs and even informal groups can deliver valuable, grassroots insights on the concerns and hopes of residents.

Public Agencies

Depending on the agency, they have the ability to bring funding resources, provide technical assistance and research, and have the authority to pass transition legislation.

Private Sector

The private sector plays an important role in economic transitions and can provide the resources and expertise necessary to bring new economies to scale.

Tribal Leaders

Tribal communities face unique opportunities and challenges in the transition away from coal. Tribal leaders bring deep knowledge of those issues that most impact their tribe.

Community Members

This group can include those who have borne the environmental impacts of the plant or mine or those whose voices are often not heard in planning discussions. Think of segments of the community who represent different races or ethnicities, lower incomes, disabilities, or other identities that may not be part of the traditional "mainstream."

Economic Development and Workforce Professionals

Organizations and agencies working on economic and workforce development can support communities and regions throughout the transition process, from addressing the immediate economic shock of a closure, to diversifying their economies and supporting the workforce into the long-term.

A list of questions to consider in Step 4 is included at the end of this guide.

FIND FUNDING

The loss of tax revenue may seem daunting when a mine or power plant closes. Your community will want to develop new businesses and revenue streams as quickly as possible. The good news is that there are many resources out there to help you.

Federal Funds

There is a wide range of federal funding that is available to assist your community with transition planning and implementation. Below are some of the common sources of federal funding and specific programs to research that may support various aspects of your transition planning process:

Appalachian Regional Commission (ARC)

- Partnership for Opportunity and Workforce and Economic Revitalization (POWER)

US Environmental Protection Agency

- Brownfields Grant Funding
- Recreation Economy for Rural Communities

US Department of Agriculture, Rural Development

- Intermediary Relending Program
- Rural Energy for America Program (Grants and Loans)
- Rural Economic Development Loan and Grant Program

US Economic Development Administration

- Public Works and Economic Adjustment Assistance
- Build to Scale

Small Business Administration

- Business Loan Program
- Entrepreneurial Development Programs

US Department of Labor

- Black Lung Disability Trust Fund
- Re-Employment, Support, and Training for the Opiod-Related (RESTORE)
- Workforce Opportunity for Rural Community (WORC)

You can find all federal funding opportunities at grants.gov.

Four Tips for Applying for Funding:

- Check to ensure your community's goals, vision, and geography align with the funding source.
- For federal sources, contact your state or regional program manager to discuss your funding request or project idea.
- Attend webinars or information sessions that the funding source may provide.
- Read the Notice of Funding Opportunity or Request for Proposals closely to determine the funder's objectives and other grant application requirements such as page length, letters of recommendation, budget information and format, and supplemental materials.

Want more information?

JTF has assisted many communities in drafting federal grant proposals to apply for EDA grants, POWER grants and Administration for Native Americans (ANA) grants. If you'd like more information about finding federal, state, or private funding opportunities for your transition efforts, we can help. Contact Cindy Winland (**cwinland@justtransitionfund.org**) and Emily Rhodes (**erhodes@justtransitionfund.org**)

A list of questions to consider in Step 5 is included at the end of this guide.

PLAN FOR THE LONG-TERM

Transition can be a time of great possibility. Think creatively about how to replace revenue and create a solid fiscal footing, good jobs, attractive spaces, a cohesive community, and a place where all generations will want to live for the long term. But you also need to plan thoughtfully—not just for the coming months or years, but for decades. Long-term planning will help ensure that the vision you collectively create accounts for the needs of all community members (and that everyone in your community understands the anticipated timeline).

Visualize Scenarios

Scenario planning is one way to help your community imagine and plan for the future. It's a technique that businesses often use to anticipate what's coming and decide how to best prepare. Simply put, scenario planning involves imagining a wide range of possibilities—even those that may seem unlikely—and talking through how to capitalize on them.

As you consider future scenarios, ask your stakeholder groups:

- What might be the effects on your community's future tax base?
- How might it change your current social structures, interactions and activities?
- What might happen to the site where the closed utility or mine now sits?
- How will each scenario make the most of and/or conserve the natural environment in your community?
- Who benefits from each future scenario?

If a mine or plant in your community has not yet closed, people may be hesitant to speak about post-closing scenarios, fearing such discussions will speed closure. Others may view planning for the unknown as a waste of time. While you may need to treat "keeping things the same" as one of several scenarios to consider, use the facts in hand to encourage your community to look past the present and keep your focus on the future.

As you continue to learn more about what a closure will mean, what assets and resources are available, and what your community wants, you can continue to revisit and rethink the possibilities together.

Create a Common Vision

Eventually, as they consider and discuss the potential scenarios, you can help your community develop a common vision for the future. Perhaps they'll want to become a regional trade hub, or an artist colony, or a key destination for outdoor enthusiasts. Whatever your community decides, keep moving the process forward by discussing what it will take to get there. Ask what success will look like in six months, one year, or five years, given what you know already. What are the holes or weaknesses that you'll need to address to achieve that success? How will you address them?

This is an ongoing and evolving conversation. Engage your community in these conversations through guided discussions, planning charrettes or even informal chats. Create ways to gather ideas online and share what you're hearing. Continue to reach out to other community members throughout the process to bring in their ideas and concerns. Expect answers to change over time as information emerges, as others get involved, and as impacts take shape.

Learn From Other Communities Moving Forward

Once you've established your leadership team and secured community input to create a common vision, much of the rest of the transition-planning process can be delegated—with clear objectives and with clearly stated expectations. This type of change management has happened in many places, under a range of conditions.

Currently, many closed plants or mines are still fenced in and untouched, demolished or vacant. However, the list of examples of successful power plant and mine redevelopment projects is continually growing. While every community has different needs, assets, and visions for a former plant or mine sites, there are examples to share to kick-start community conversations. Find other communities that have faced similar situations and learn what they did that worked and what they would have done differently in retrospect. Identify the key actors and influencers in those communities, both positive and negative. Examples of transition efforts are abundant, and although many are related to other types of economic change, they contain relevant ideas and lessons for communities struggling with an economic transition away from coal.

A list of questions to consider in Step 6 is included at the end of this guide.

About the Just Transition Fund

The Just Transition Fund helps communities affected by the changing coal industry and power sector make the transition to a new economy. We provide both direct investments to help communities create 21st century jobs and technical assistance to empower local leaders to act.

Our work on the ground is visible across the country, from Western New York to Minnesota to Montana. In Buffalo, New York, we helped write a bold and pragmatic community transition plan that is being implemented. In Colstrip, Montana, we're helping facilitate a state-led community engagement process to develop a long-term plan for the use of $10M in utility-supplied transition funds. And in Minnesota, we're supporting city managers in multiple power plant communities to conduct an economic impact analysis.

For more information about the Fund's direct technical assistance, or for help in your community, contact Cindy Winland (cwinland@justtransitionfund.org).

How to Get Started: Key Questions for Local Engagement in Transition

The Just Transition Fund works on the ground in communities that are responding to coal plant closures. The following questions can help affected communities begin a transition-planning process.

Engage Early (Build your transition leadership team)

- [ ] Which key stakeholders have the knowledge about various aspects of our community? (economic, social, etc.)
- [ ] Which community leaders are considered unbiased?
- [ ] Who has influence in the public, private, or nonprofit sectors and can attract more support for our work?
- [ ] Which representatives of the utility or mine and/or property owners of the site might best contribute to our process?
- [ ] Which government, labor, issue experts, community members, academia, faith, and/or philanthropic organizations might we want to engage?
- [ ] Who does our community trust?
- [ ] Who has not been at the table previously whose voice needs to be heard?

Find Out the Facts

- [ ] Where do tax dollars originate currently and how are they spent?
- [ ] Are there state or federal matching funds at risk if our community can no longer provide its share?
- [ ] What's the value of the nonfinancial support the community gets from the utility or mine in question?
- [ ] How might the social and cultural fabric of our community change?
- [ ] What are the properties and structures the mine or utility will leave behind after closure?
- [ ] What will a closure do to our community's infrastructure?
- [ ] What are our community's other assets that can contribute to a successful transition?

Bring the Community Together

- [ ] Who in our community is most likely to be immediately affected by a closure?
- [ ] In addition to jobs lost at the mine/utility, what other jobs might be directly or indirectly at risk?
- [ ] Which schools or nonprofits in our community will suffer a decline in volunteers or charitable giving if people move away?
- [ ] What government agencies or services are most at risk? Who do they serve?
- [ ] How will a loss of tax revenue impact our local government's binding, debt retirement, insurance, infrastructure, etc. that support quality of life for everyone?
- [ ] Who has influence in the community and how can this influence be used positively?

- What groups will lend a perspective that we might otherwise overlook? (e.g. labor unions or environmental groups)
- Who can help the community find funding for fostering transition outcomes?
- Who else in our community can contribute to positive change?

Engage Diverse Stakeholder Perspectives

- What does a successful transition mean to different stakeholders?
- What vision do all stakeholders hold in common? What priorities?
- What value can each stakeholder group bring to our process?

Find Funding

- What are the likely impacts on our local tax revenue, and what might that mean in terms of public services?
- What relationships can we leverage at the state or federal level?
- What support or resources do we have to contribute to a transition planning or implementation effort?
- What support or resources do we most need to participate in that effort?

Plan for the Long Term

- What are the outcomes we want to see?
- What assets do we have that we can deploy to achieve those outcomes?
- What hurdles will we need to overcome and how will we address them?
- What has happened in other places that can serve as a model for our positive transition?
- What is the transition timeline and what are the milestones we want to achieve after one, five, or ten years?
- What are the "early wins" we can achieve that will help motivate our community and provide a sense of hope?

ROCKY MOUNTAIN INSTITUTE

MANAGING THE COAL CAPITAL TRANSITION

COLLABORATIVE OPPORTUNITIES FOR ASSET OWNERS, POLICYMAKERS, AND ENVIRONMENTAL ADVOCATES

BY ANNIE BENN, PAUL BODNAR, JAMES MITCHELL, AND JEFF WALLER

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EXECUTIVE SUMMARY

Coal was the preeminent fuel for grid-based electricity generation around the world for the better part of a century, but its time is coming to an end. With this transition, however, workers and communities are experiencing layoffs and the owners of coal-fired power plants are bracing themselves for hundreds of billions in write-offs. This report intends to start pragmatic conversations on the coal capital transition: the collaborative management of capital exit from coal-fired generating assets in line with their decreasing economic competitiveness compared to clean energy, and in line with the objective of limiting global warming to well below 2C°.[i]

The early retirement of coal plants across the world has enormous financial implications for asset owners, policymakers, and environmental advocates alike. Managing the exit of capital from coal-fired generating assets demands thoughtful and collaborative planning among these stakeholders.

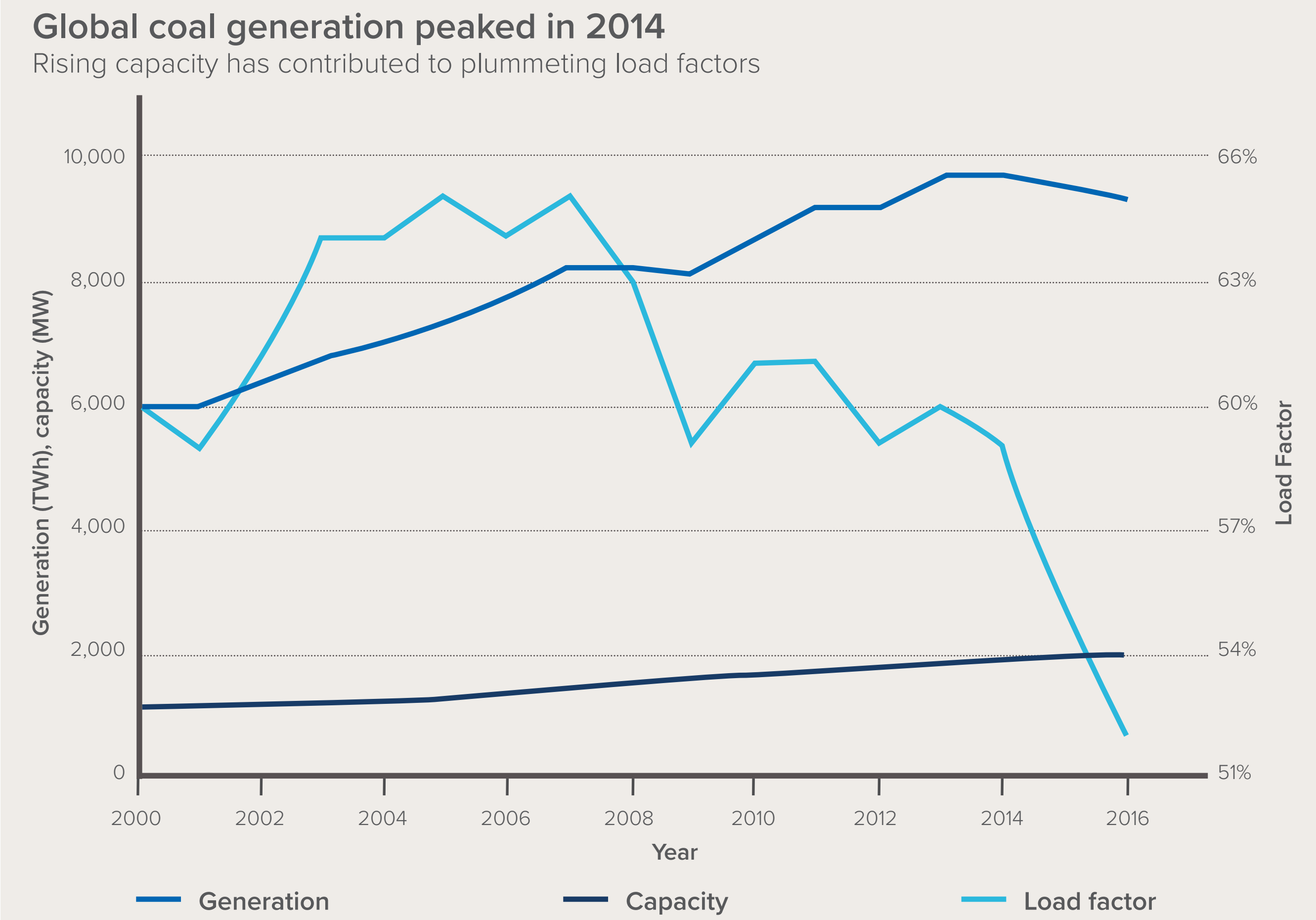
Coal-fired power generation is in structural decline, and its role the global energy mix will continue to diminish due primarily to economics. This erosion is structural, not cyclical, and is driven predominantly by cheap gas, inexpensive renewables, and the costs associated with complying with environmental regulations that seek to reduce air pollution and address climate change.

Photo courtesy Al Braden for the Sierra Club. Sandow Coal Plant in Rockdale, Texas, which closed in 2018.

[i] While most people are familiar with the expression "degrees Celsius" (ºC), that expression signifies an absolute temperature that represents the coolness or warmth of something. The expression "Celsius degrees" (Cº) refers to an interval between two measured temperatures, which in this paper denotes temperature rise above preindustrial levels.

FIGURE ES1

TRENDS IN GLOBAL COAL-FIRED POWER GENERATION



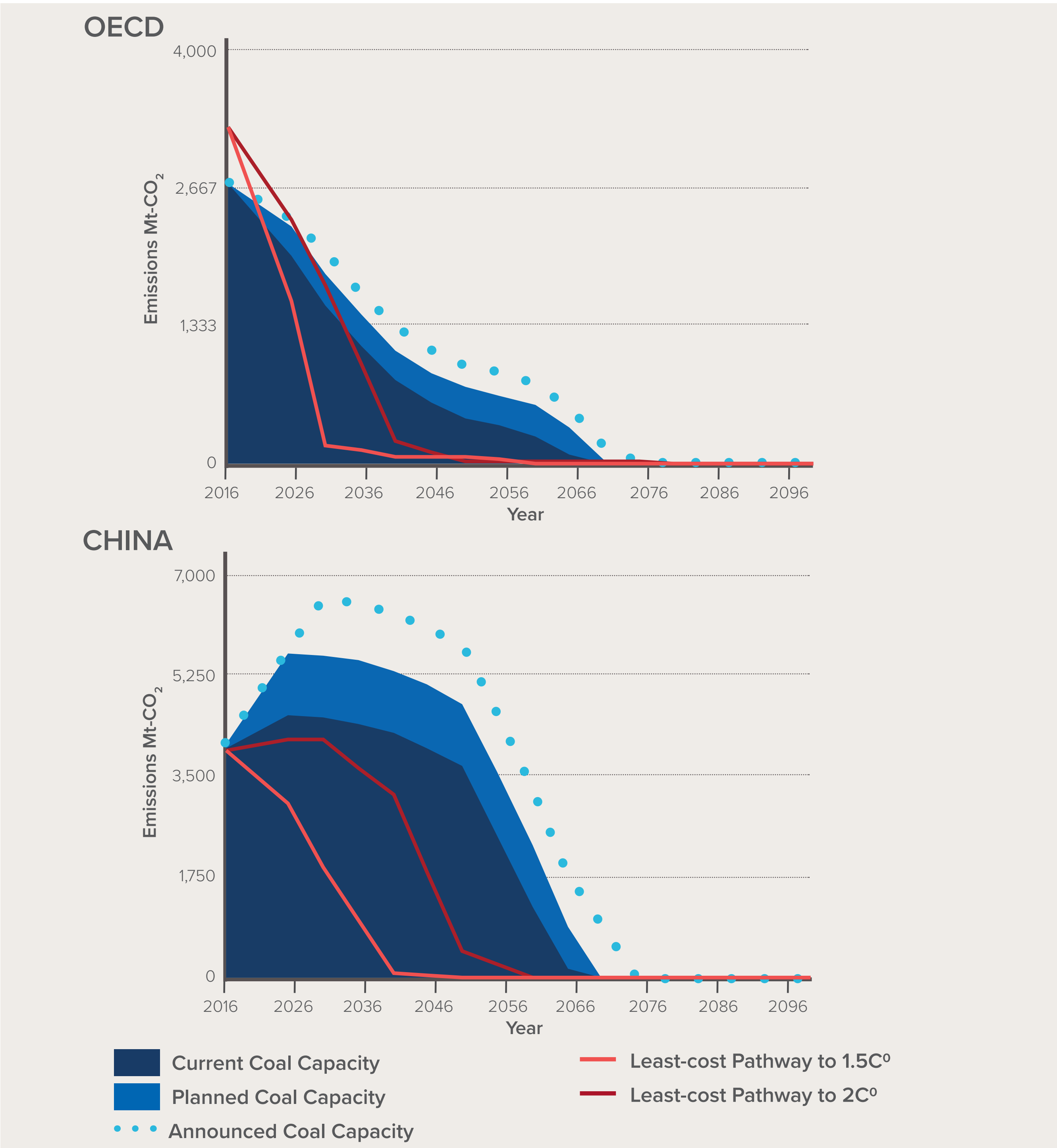
Source: Carbon Brief analysis

The clear downward trend for coal power increases the likelihood of widespread stranded assets and capital destruction. Coal-fired power plants around the world that were designed to operate for decades longer are under pressure to shut, in many cases before associated debt has been paid off. Whether these assets are stranded because of changing economics or regulations (or a combination of the two), coal plants worldwide are at high risk for creating **stranded value** for owners—that is, the assets' actual financial returns will be less than what had been expected at the time of initial investment.

While economic trends are slowing the growth of coal capacity and leading to a significant amount of uncompetitive coal-fired capacity to shutter, **these trends alone will not be sufficient to reduce global greenhouse gas emissions consistent with the Paris Agreement objective of holding warming well below 2 C°.** Leaving aside planned or announced coal plants not yet online, emissions from the existing coal power plant fleet alone exceed levels consistent with globally agreed temperature goals.

FIGURE ES2

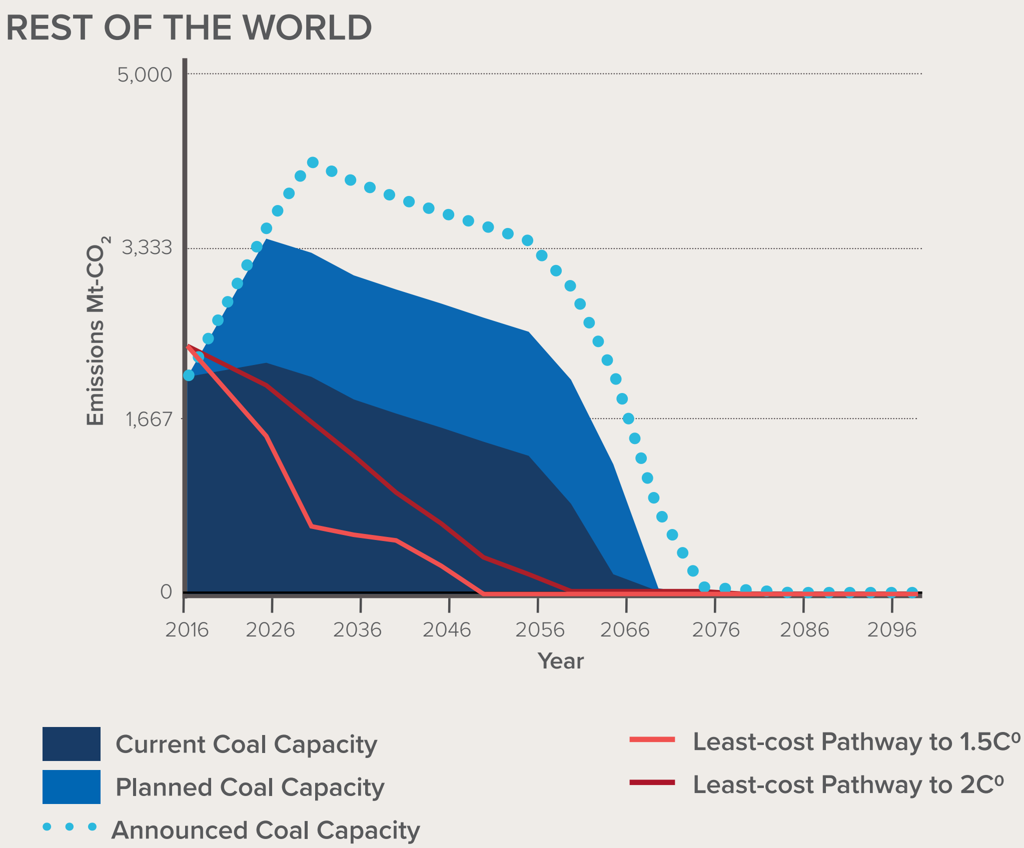
POTENTIAL CO_2 EMISSIONS FROM EXISTING AND PLANNED COAL CAPACITY AGAINST LEAST-COST PATHWAYS



(Figure ES2 continued on next page)

FIGURE ES2

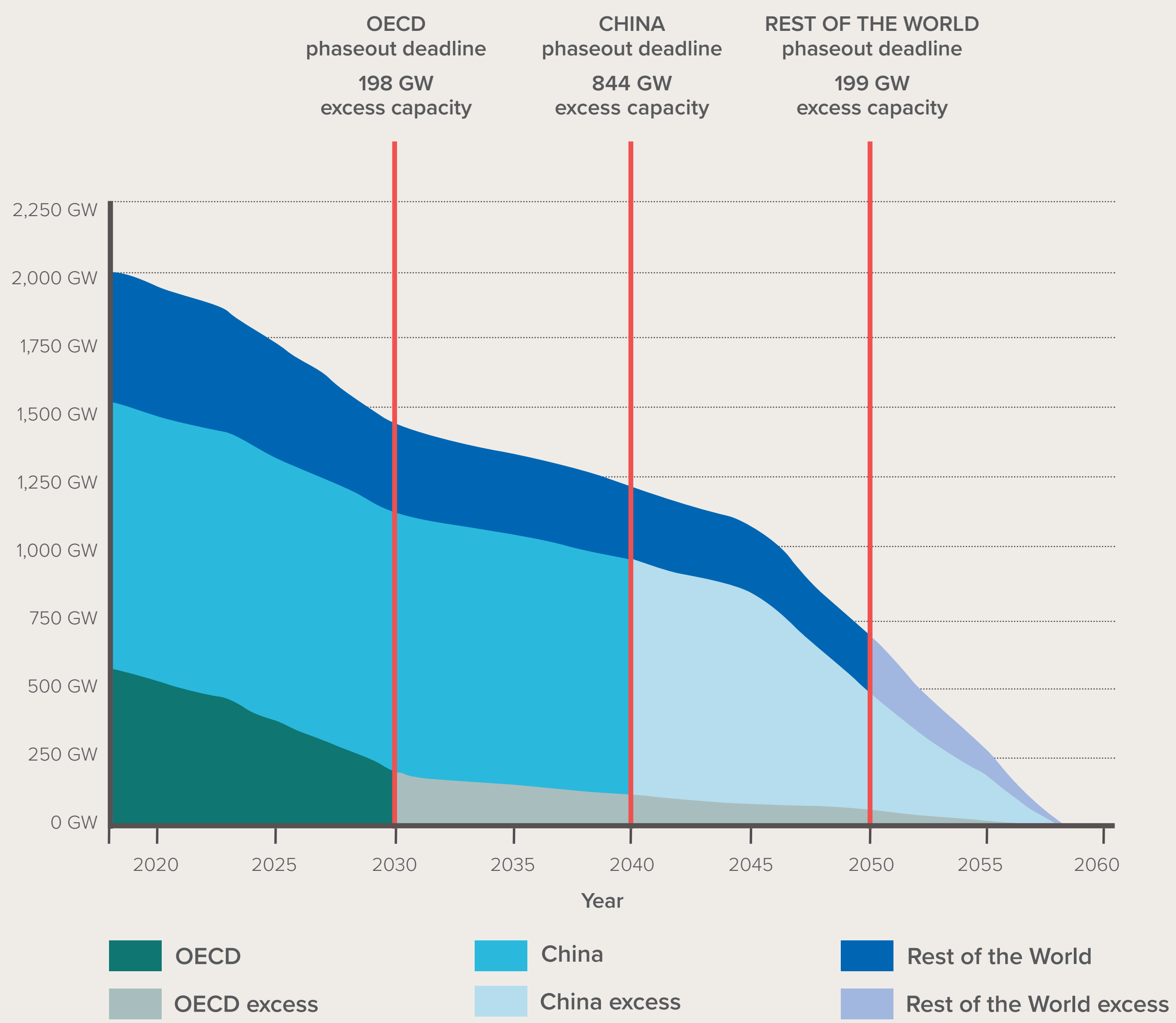
POTENTIAL CO_2 EMISSIONS FROM EXISTING AND PLANNED COAL CAPACITY AGAINST LEAST-COST PATHWAYS



Source: Analysis by Climate Analytics of least-cost pathways for regional coal phaseout

FIGURE ES3

NATURAL RETIREMENT OF CURRENT COAL CAPACITY ON STATED RETIREMENT DATE VS. LEAST-COST PHASE OUT BY REGION SHOWS NECESSARY PREMATURE RETIREMENT



Source: CoalSwarm analysis using the CoalSwarm Global Coal Plant Tracker data

Under least-cost pathways for holding warming **well below 2C°**, coal closures would need to begin immediately across all regions and be completed by roughly 2030 for Organisation for Economic Co-operation and Development (OECD)/European Union (EU), 2040 for China, and 2050 for the rest of the world. Based on the actual technical lifetimes of the existing coal fleet, **significant early retirement of current capacity would be necessary, including** 198 GW in the OECD, 844 GW in China, and 199 GW in the rest of the world. This holds the potential to strand hundreds of billions of dollars of value globally.

The specter of capital losses fuels opposition to policies aimed at accelerating the energy transition. From the perspective of asset owners, lobbying against climate and clean energy policy is an economically rational response to prospective stranding. As a result, the energy transition is happening in fits and starts. For their part, environmental advocates have focused on the adjustment costs for labor and communities associated with layoffs and the need for a just transition for labor. However, this problem-solving approach has only just begun to be applied to the prospect of write-offs. We recommend it be considered more consistently.

With a better understanding of an asset owner's legitimate day-to-day business perspective, policymakers and advocates can better appreciate how coal plant owners assess their plants' current and future financial performance. More importantly, a nuanced understanding of this financial perspective can help anticipate an owner's likely business strategies, political positions, and amenable exit options, positioning them well to engage directly with owners to proactively manage the coal capital transition. The Asset Position Framework does this by classifying assets into one of four positions based on their current and projected future financial performance: *continuing operator, short-term opportunity, exit opportunity,* and *wait and see.* An asset's position on the framework will determine an owner's likely business strategy with the asset, political strategies, and asset exit options.

FIGURE ES4

ASSET POSITION FRAMEWORK

For asset owners, proactive planning for the end of the coal era can preserve shareholder value and avoid financial shocks to equity and debt holders alike. Policymakers and advocates focused on climate objectives are seeking ways to accelerate the transition of energy sector capital stock from brown to green, including through early retirement of coal assets. But stranding these assets is not—and should not be—the goal; the loss of value associated with stranded assets is an undesirable consequence that, while to some extent inevitable, should be actively mitigated to ensure that all stakeholders are on board with the direction of the energy transition. Instead, policymakers have an opportunity to understand and implement a new toolkit to spur faster energy transition through dialogue rather than adversarial approaches. And environmental advocates can advance their objective of accelerating the clean energy transition and avoid costly and lengthy conflicts with incumbents. Regardless of the region or market circumstance, it is in the interest of owners, policymakers, ratepayers, and other stakeholders to develop a managed plan for capital transition that can reasonably limit losses and allocate them appropriately.

This report is the first global survey of approaches that can help ease capital destruction for asset owners and their shareholders while offering policymakers a clearer path toward transitioning the power sector onto a below-2C° pathway.

The following table describes the 10 policy components for managing the capital losses associated with early retirement of coal-fired generating assets. It also identifies the factors that influence the applicability of components and the potential challenges of including them in policy design.

TABLE ES1

10 POLICY COMPONENTS TO MANAGE THE COAL CAPITAL TRANSITION

POLICY COMPONENT	BEST APPLICABILITY	BEARER OF LOSSES (PROXIMATE)	DESCRIPTION	POTENTIAL CHALLENGES
Mandate Closure	Liberalized and state-managed markets	Asset Owner	Regulators set a date by which some/all coal-fired power must be decommissioned.	Impact investment climate
Full or Partial Disallowance	Regulated markets		Regulators determine that asset should be removed from the rate base and owner is no longer allowed to make a return on the asset.	Impact investment climate
Impose Costs	Liberalized and state-managed markets		Regulators change operating economics by increasing costs via carbon pricing or mandated pollution standards.	• Impact investment climate • Ratepayer pass-through
Remove Alternative Revenue Sources	Liberalized markets		Regulators change coal operating economics by removing ancillary revenues such as subsidies, capacity payments, or reserve payments.	Impact investment climate
Offset Losses	• All markets • Funds available • High policymaker capacity		Regulators allow owners to utilize non-coal-related funds to offset losses created by early closure of a plant, e.g., selling unused emissions allowances or monetizing carried-over tax credits.	Moral hazard
Create Regulatory Asset	• Regulated markets • Funds available • High policymaker capacity		Regulators allow cost recovery from rate base after asset retirement by utilities in regulated markets.	• Ratepayer pass-through • Moral hazard
“Soften the landing”	• All markets • Funds available		In combination with an approach that will force closure by a certain date, offer alternative revenue streams in the interim to maximize cost recovery before early closure.	• Ratepayer pass-through • Moral hazard
Accelerate Depreciation Schedule	All markets		Minimize write-offs at closure by accelerating depreciation before closure. Amount and type of recovery of incremental depreciation expense varies.	• Ratepayer pass-through (regulated markets) • Moral hazard
Take-over and Write-off	• Regulated or state-managed • Funds available		In state-managed markets, the government purchases the asset and writes off the debt. This requires that the government decommission, not mothball, the asset. Otherwise, a risk remains that the asset could be resold to a third party who then continues operation.	Moral hazard
Pay to Close	• All markets • Funds available	Government	Government offers direct compensation payments for closure, negotiated based on valuation of plant and whether full compensation will be paid.	Moral hazard

In considering these options, six factors stand out as especially important in shaping policy choice:

1. **Power market type.** Some policy options apply only to regulated markets.
2. **Policymaker capacity.** Some policies require significant decision-making authority on the part of policymakers, as well as technical and resource capacity for implementation.
3. **Bearer of losses.** Every approach improves the value proposition of asset retirement by either worsening the economics of continued plant operation or increasing the benefits of closure. This requires that capital losses are borne by some combination of government and/or asset owners.
4. **Ratepayer impact.** The application of some approaches may increase costs to ratepayers, which has important implications for policy design and implementation.
5. **Investment climate.** If policy actions are perceived as capricious or unwarranted, they can erode trust between regulators and business.
6. **Moral hazard.** Approaches where the government bears the losses—in the form of compensation to owners—typically carry a degree of risk of moral hazard.

COMBINING POLICY COMPONENTS

The 10 policy components for managing capital losses discussed above are presented individually to highlight the applicability and challenges of each. In practice, however, combining policy components provides flexibility both with the timing of policy implementation, as well as with the ability to allocate—or reallocate—losses across parties. For example, a comprehensive policy could include a future mandated coal phaseout date combined with components designed to alter the coal plants' operating economics. The aim of these components could be to encourage faster retirement (e.g., by including environmental regulations that impose escalating costs) or to provide increased interim compensation to allow coal plant owners to maximize the return on their investment prior to the phaseout date (e.g., by offering alternative revenue streams). Four case studies of coal closures in Alberta, Chile, China, and Colorado demonstrate that there are no one-size-fits-all solutions. Complete policy packages are built from the ground up using policy components fit to their specific context.

RECOMMENDATIONS

Managing the financial implications of stranded coal assets requires a balanced perspective that takes into account the perspectives of three major groups: coal plant asset owners, who stand to bear the burden of capital losses associated with premature closure of coal-fired generating assets; environmental advocates, who seek to accelerate coal phaseout in line with the objectives of the Paris Climate Agreement; and policymakers, who must balance the environmental necessity of accelerated coal plant retirement with thoughtful, managed allocation of the associated capital losses.

POLICYMAKERS

- **Understand the context.** The economics of operating coal plants vary by geography and by plant. Depending on the financial position of individual plants or portfolios, asset owners may be looking for, or be open to, an exit strategy.

- **Shift the conversation.** The challenge is to present an alternative economic equation to asset owners that is sufficiently attractive to encourage acceptance rather than resistance to the notion of early asset closure.

- **Know your options.** The 10 strategies presented in this report are grounded in a global survey of approaches that have been formulated in various jurisdictions to address this issue.

- **Customize.** There is no one-size-fits-all policy solution. Components can be combined to create a package tailored to the needs of all stakeholders involved. Depending on the chosen approaches, the question of policy institutions' technical and human capacity to design and implement the solution can be critical.

- **Build support.** Thoughtful, managed allocation of the associated capital losses through combinations of the strategies surveyed in this report—and others that have not yet been designed—can build support among key political constituencies. Key to productive dialogue is ensuring that outcomes are viewed as equitable among all stakeholders impacted by stranded assets.

- **Balance risk.** In formulating coal capital transition strategies, policymakers should carefully balance maintaining the credibility of the local investment climate with the serious issue of moral hazard.

ASSET OWNERS

- **Acknowledge trends.** It's time to acknowledge that coal-fired power generation is in structural decline worldwide. While there are and will continue to be exceptions, eroding economics and declining load factors globally demonstrate this clearly, regardless of one's view of the merits or durability of climate policy.

- **Recognize that the risk of stranded value is real.** While the decline of coal-fired power generation is at different stages in different geographies, some capital destruction associated with early closure due to both economic and regulatory stranding is inevitable.

- **Leverage the benefits of planning.** Proactive planning for the end of the coal era can preserve shareholder value and avoid financial shocks to equity and debt holders alike.

- **Understand what's feasible.** Asset owners should acknowledge that from a policymaker's perspective, they rarely have claim to compulsory compensation and that moral hazard is a real and legitimate concern. Still, policymakers also have a strong incentive for pragmatic dialogue.

- **Build on existing dialogues.** While they may feel frequently at odds with environmental advocates, coal asset owners should build on the principles for just transition of labor.

ENVIRONMENTAL ADVOCATES

- **Understand the owner's perspective.** To accomplish the early retirement of the coal fleet requires acknowledging that from an asset owner's perspective, opposing policies that would cause such financial hardship is economically rational.

- **Link to a "just transition."** If environmental advocates are serious about neutralizing political opposition to climate action, they need to look seriously at rational decisions motivating this opposition. Therefore, an integrated approach to addressing layoffs and write-offs associated with early coal plant retirement is essential.

- **Manage trade-offs.** Many of the solutions presented here come with difficult trade-offs, using funds that will undoubtedly be limited. Advocates must work alongside policymakers and asset owners to ensure that these trade-offs are being weighed appropriately. Once agreements are reached, advocates must enforce those agreements in the public sphere.

EXECUTIVE SUMMARY

Solar with Justice

Strategies for Powering Up Under-Resourced Communities and Growing an Inclusive Solar Market

Clean Energy States Alliance • Jackson State University Department of Urban and Regional Planning

Partnership for Southern Equity • PaulosAnalysis • University of Michigan School for Environment and Sustainability

The Nathan Cummings Foundation • The Solutions Project

Acknowledgments

Many people and organizations helped produce this report. The project was a team effort by the 11 authors with the help of their respective organizations.

The idea for this report emerged as a recommendation from grantee partners who attended a 2018 convening on community-owned and community-determined solar that The Nathan Cummings Foundation and The Solutions Project co-hosted. The concept for the convening originated from Sharon Alpert, president of The Nathan Cummings Foundation, and Sarah Shanley Hope, executive director of The Solutions Project.

The authors are grateful to the 82 people who participated in general research interviews for this report. Their names and organizations are listed in Appendix C. We particularly wanted to gather and learn from the perspectives of leaders of frontline community organizations focused on energy equity. We included many of these community leaders in our interviews and in a kickoff workshop in January 2019, which helped set the research agenda for the project. The workshop participants are listed in Appendix D.

We very much thank the approximately 20 people who provided us with information for the report's case studies through interviews and correspondence. We hope they will feel that we portrayed their admirable projects accurately and appropriately, but only the authors are responsible for any errors or misrepresentations.

JC Burton of Woodline Solutions helped pull the project team together and helped set the stage for its work. Anthony Giancatarino of the Movement Strategy Innovation Center, Seth Mullendore of Clean Energy Group, Summer Sandoval of UPROSE, and Elaine Ulrich of the US Department of Energy read a draft of some or all of the report and provided us with useful comments that improved the final product. Refugio Mata and Cat Lazaroff of Resource Media gave us sound advice on how to structure and present the report so that it would reach its intended audiences. Valerie Bouchard, Mandy Van Deven, and Candice Wynter of The Nathan Cummings Foundation provided valuable input and connected us with stakeholders who informed the final report.

Maria Blais Costello, manager of program administration for the Clean Energy States Alliance, was responsible for report production, including copyediting the report, working with the graphic designer, and coordinating all the myriad details that go into producing a document of this size and scope. Diana Chace assisted with proofreading the report. David Gerratt of DG Communications designed the final product.

We very especially thank The Nathan Cummings Foundation for making this report possible.

For More Information

Information about this project is available on the website of the Clean Energy States Alliance (CESA) at *www.cesa.org/projects/low-income-clean-energy/solar-with-justice*. To reach the project team, contact:

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On the Cover Photo
A one-megawatt solar project by and for the Soboba Band of Luiseño Indians in Riverside County, California. The project serves the 1,320 members of the tribal community, most of whom live on the Soboba Reservation.

Solar with Justice

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December 2019

To access this report online, please visit https://cesa.org/resource-library/resource/solar-with-justice.

Sunwealth

RE-volv

EXECUTIVE SUMMARY

Under-resourced communities face a disproportionate share of societal burdens and lack access to many of the benefits other communities enjoy. Participation in the solar economy can help ease these burdens and provide low- and middle-income (LMI) households with economic relief. In addition to the obvious benefit of helping to reduce consumers' electricity costs, solar can also reduce electricity shutoffs from non-payment, provide jobs in under-resourced communities, reduce residents' exposure to pollution, diminish the use of potentially dangerous heating sources, and make critical community facilities less vulnerable to power outages from extreme weather events and other electricity disruptions.

The supply and quality of affordable housing can be improved by including solar and allowing roof repairs as part of the rooftop solar installation process, and by creating savings for affordable housing providers that can be leveraged toward preserving and expanding affordable housing. Solar on buildings that house nonprofits can provide utility bill savings that can be redirected to programs and mission-related activities. Solar on single-family homes can increase the home's value. Solar can also make decision-making more democratic by giving residents of under-resourced communities more control over their energy choices.

The goal for the *Solar with Justice* report is to accelerate the implementation of solar in under-resourced communities* in ways that provide meaningful, long-lasting benefits to those communities. The recommendations in the report set a path forward for increasing solar deployments that result in significant economic, equity, and health improvements.

* This report defines "under-resourced communities" as ones that have high proportions of LMI residents and generally receive below average services and financial resources from government. Many, but not all, comprise an above average number of people of color and immigrants.

Building Equity into Solar Development

Representatives of frontline organizations want solar development to be a vehicle for strengthening community-based organizations and building community wealth. But their prior experiences—on a range of issues other than solar—have made them wary of outsiders coming into the community and making decisions for them. For solar to meet the needs of under-resourced communities and to be perceived as beneficial, the community must feel that solar development is something being done *by them* rather than *to them*.

Community empowerment is the process of building leadership capacity within a community to increase community-led decision-making. It is not enough to turn decision-making over to community organizations and residents if they do not have the resources and subject-matter knowledge to deal with a technically complicated subject like solar development, or if legal and financial barriers prevent them from being positioned as solar project beneficiaries. The elements of creating community empowerment can include the following:

1. Establishing trust
2. Educating the community
3. Building organizational capacity and developing leadership
4. Addressing barriers and biases
5. Involving relevant stakeholders in constructive engagement
6. Increasing community wealth
7. Mobilizing resources for program sustainability

Obstacles to Solar for Under-Resourced Communities

There are significant obstacles to deploying solar in a manner that results in the tangible benefits accruing to under-resourced communities. The most obvious barrier for low-income customers is that they have low incomes, which can make it difficult to build financial wealth. Although solar can provide savings on utility bills, and thus reduce energy burdens, LMI households generally need assistance to overcome the initial up-front cost hurdle of going solar. Efforts to enable low-income customers to benefit from solar must also consider a larger set of barriers, including policy, finance, and regulatory obstacles. This report examines ten obstacles and market challenges that must be addressed to successfully deploy solar in under-resourced communities:

1. The solar market is still developing in many places
2. Lack of solar marketer interest and customer awareness in under-resourced communities
3. Financial barriers for community institutions
4. Competition between solar and existing LMI energy programs
5. Policy barriers
6. Utility opposition
7. Competing priorities for advocates and service groups

8. Housing policies

9. Finance policies

10. Vestiges of discriminatory practices and residential segregation

Recommendations

Solar with Justice offers a series of recommendations for advancing solar for under-resourced communities, including the context behind each recommendation and advice on how to implement it. The recommendations from each chapter are listed below for easy reference, though in some cases, it may be necessary to read the explanations in the report to fully understand the reason for, or implications of, the recommendation.

The general findings and recommendations presented in Chapter 4 apply to a range of participants in the solar market. At the top of the list: partnerships with trusted community organizations are central to successful solar development for under-resourced communities.

Top Ten General Findings and Recommendations (Chapter 4)

1. Partnerships involving trusted community organizations are essential
2. It's still the experimental phase for LMI solar
3. Installations for community institutions deserve special consideration
4. Resilience should be a component of LMI solar
5. Financial risk needs to be minimized for LMI households and community organizations

DOE/Chris Collins

6. Strong consumer protection is crucial
7. Shared solar projects can play a useful role, but they are not a panacea
8. Training and workforce development should remain a priority
9. Solar education is important
10. Increasing the availability of financing for solar projects in under-resourced communities is essential

Most of the report's recommendations are targeted at specific key stakeholder groups: state governments, community organizations, philanthropic foundations, the solar industry, municipalities, investors. The aim is to help each group channel its efforts in productive ways.

Recommendations for State Governments (Chapter 5)

1. Measure progress towards energy equity
2. Make sure pro-solar state policies are in place
3. Adopt special incentives and policies
4. Leverage private capital
5. Work with and help community organizations
6. Bring LMI issues into public utility commission proceedings
7. Design solar programs for specific market segments
8. Ensure financial benefits reach LMI households
9. Impose high consumer protection standards

Recommendations for Philanthropic Foundations (Chapter 6)

1. Incorporate input from community groups
2. Support frontline organizations with unrestricted multi-year grants
3. Invest in projects with a strategic focus
4. Leverage financing and program-related investments to de-risk projects
5. Provide funding to determine the most viable community empowerment models for solar
6. Lean in to challenging locations to accelerate equity in solar access
7. Leverage strategic new channels to teach LMI households

Recommendations for Community Organizations (Chapter 7)

1. Insist on the involvement of community organizations
2. Develop an internal education plan
3. Engage the community in dialogue on solar

DOE/Greg Johnstone

4. Control the decision-making process and make careful decisions about project ownership
5. Push for community benefit agreements
6. Identify key institutions and help them adopt solar
7. Take part in shaping policy

Recommendations for Other Stakeholders (Chapter 8)

1. Solar businesses should seek local partners
2. Solar businesses should have a plan for workforce development
3. The solar industry should self-police
4. Local governments can support solar that benefits LMI communities and residents
5. Communities with municipal utilities and electric coops have special opportunities
6. Large electricity users can help shared-solar projects work for LMI households

Recommendations for Expanding and Improving Project Financing (Chapter 9)

1. Build capacity so that community-led development teams and financing institutions can successfully implement projects
2. Present credible solar information in familiar formats
3. De-risk project finance for financial institutions and borrowers

4. Use alternatives to FICO credit scores
5. Negotiate project ownership and distribution of benefits

At the end of most of the chapters, we provide brief descriptions of promising initiatives that others can learn from and emulate. Additionally, we have included extended case studies in several chapters to showcase some of the most inventive approaches that organizations have taken to advance solar for under-resourced communities. Key take-aways from each of the case studies are noted, as well as the types of groups and organizations that could replicate the model presented in the case study.

Case Studies

1. Connecticut Green Bank brings solar to LMI homeowners
2. Energy Trust of Oregon engages community groups to create replicable solar development models
3. The Kresge Foundation provides credit enhancements to finance resilient power projects
4. LaGrange Housing Authority project catalyzes ongoing solar development by an innovative community organization
5. PUSH Buffalo incorporates solar into a mixed-use project with community asset ownership
6. UPROSE's Sunset Park Solar creates New York's first cooperatively owned shared solar project
7. Native Renewables builds energy independence
8. Denver Housing Authority applies shared solar to benefit affordable housing
9. Fellowship Energy arranges for solar energy for faith-based communities
10. RE-volv provides opportunities for nonprofits serving under-resourced communities to install solar energy
11. Investment firm Sunwealth delivers tangible social impact along with strong investor returns

The Report's Origins and Distinguishing Features

The *Solar with Justice* report's meetings, research, writing, and production were funded by The Nathan Cummings Foundation. The need for the project emerged from an early-2018 workshop of its grantees, partners, and thought leaders that was co-convened by the Foundation and The Solutions Project on the topic of community-owned and community-determined solar. Attendees at the workshop identified a strong need for information and recommendations on solar best practices for under-resourced communities.

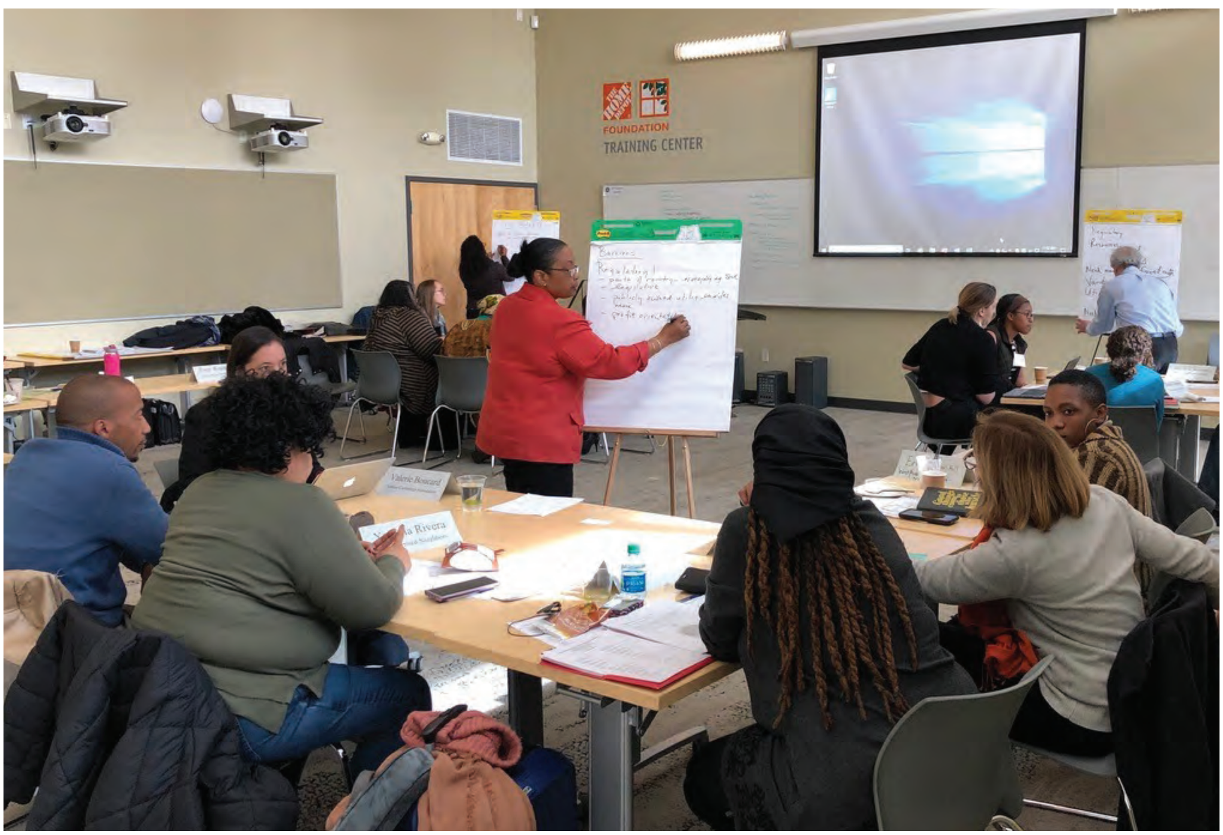
Although other useful reports have been published on the topic of solar for LMI households and communities, our report has four key distinguishing features:

- ***A diverse team worked together to explore solar in under-resourced communities in a comprehensive, integrated manner.*** The project team not only examined solar technologies, solar policies, and solar market trends, but we also considered the needs and perspectives of residents of under-resourced communities. We put together a project team with deep and varied experience working on solar policy, energy equity, community development, and project financing.

- ***The report gathered the viewpoints of many experts from across the country***. In addition to desktop research, the project team conducted 76 interviews with 82 leaders and experts from across the country. We spoke with leading solar project developers, investors, community leaders, advocates, and representatives of national NGOs, the federal government, state governments, financial institutions, and solar companies. More than 10 additional interviews were conducted as part of the research for the report's case studies.

- ***The views of leaders of community organizations were given special attention.*** We especially wanted to hear and understand the perspectives of leaders of frontline community-based organizations working for energy equity and climate justice. Those voices are frequently missing from reports prepared by national organizations working on energy issues. We kicked off the project with a full-day workshop in Atlanta in January 2019 with 14 representatives of frontline community-based organizations. Later interviews and a video conference on draft recommendations ensured that the perspectives of community group leaders continued to be heard.

- ***The report makes clear recommendations***. Rather than simply describe the solar market and present dozens of possible program options without evaluating them, this report presents very clear recommendations aimed at the most important stakeholder groups that can shape the future of solar for under-resourced communities.



Clean Energy States Alliance

Solar with Justice

Strategies for Powering Up Under-Resourced Communities and Growing an Inclusive Solar Market

The Clean Energy States Alliance (CESA) is a national, nonprofit coalition of public agencies and organizations working together to advance clean energy. CESA members—mostly state agencies—include many of the most innovative, successful, and influential public funders of clean energy initiatives in the country. CESA facilitates information sharing, provides technical assistance, coordinates multi-state collaborative projects, and communicates the views and achievements of its members. *www.cesa.org*

Jackson State University (JSU) is a historically Black, research-intensive public institution of higher education in Mississippi. JSU's mission is built upon three pillars of success—student centeredness, teamwork, and the pursuit of excellence. The Department of Urban and Regional Planning at JSU offers the only accredited Urban Planning programs in the state, producing highly knowledgeable, skilled graduates who can significantly contribute to building healthy and sustainable communities. *www.jsums.edu*

The Partnership for Southern Equity (PSE) is an Atlanta-based nonprofit that advances policies and institutional actions that promote racial equity and shared prosperity in metropolitan Atlanta, the state of Georgia, and the American South through an ecosystem-based model for multi-demographic engagement. Focusing on four key areas—energy, growth, health, and opportunity—PSE has developed strong partnerships, which result in successful policy initiatives that elevate the communities it serves. *www.psequity.org*

PaulosAnalysis provides research and consulting on clean energy policy, technology, and trends, for non-profit, media, industry, research, and philanthropic clients. *www.paulosanalysis.com*

The School for Environment and Sustainability's overarching objective is to contribute to the protection of the Earth's resources and the achievement of a sustainable society. Faculty, staff, and students are devoted to generating knowledge and developing policies, techniques, and skills to help practitioners manage and conserve natural and environmental resources to meet the full range of human needs on a sustainable basis. *www.seas.umich.edu*

The Nathan Cummings Foundation is a multigenerational family foundation, rooted in the Jewish tradition of social justice, working to create a more just, vibrant, sustainable, and democratic society. We partner with social movements, organizations and individuals who have creative and catalytic solutions to climate change and inequality. *www.nathancummings.org*

The Solutions Project accelerates the transition to 100% clean energy for 100% of the people, and does so by working with grassroots organizations to build an inclusive, celebratory, and collaborative culture. It invests in frontline women and leaders of color positioned for impact—helping to amplify their stories and scale their clean energy solutions. It recently committed to invest 95% of its philanthropy in people of color and women-led organizations. *www.thesolutionsproject.org*

To access this report online, please visit
https://cesa.org/resource-library/resource/solar-with-justice.

Electric Vehicles (EVs)

Electric Vehicles (EVs)

Key Definitions

The following definitions are taken directly from Energy.Gov:

- **EVs** (also known as plug-in electric vehicles) derive all or part of their power from electricity supplied by the electric grid. They include AEVs and PHEVs.
- **AEVs** (all-electric vehicles) are powered by one or more electric motors. They receive electricity by plugging into the grid and store it in batteries. They consume no petroleum-based fuel and produce no tailpipe emissions. AEVs include Battery Electric Vehicles (BEVs) and Fuel Cell Electric Vehicles (FCEVs).
- **PHEVs** (plug-in hybrid electric vehicles) use batteries to power an electric motor, plug into the electric grid to charge, and use a petroleum-based or alternative fuel to power the internal combustion engine. Some types of PHEVs are also called extended-range electric vehicles (EREVs).

Key Arizona Statistics

- According to Plug In America, more than 1.6 million plug-in vehicles have been sold in the U.S. with over 40 EV models available today and over 100 EV models expected to be available by 2022.
- According to Auto Alliance's most recent data (Jan. 2018-June 2019), there are 21,500 plug-in vehicles registered in Arizona, ranking our state 11th in plug-in vehicle market share.

Significant Policies & Opportunities Under Consideration in Arizona

- In December 2018, the Southwest Energy Efficiency Project (SWEEP) and Western Resource Advocates (WRA) released a study, Electric Vehicle Cost-Benefit Analysis for Arizona, they commissioned M.J. Bradley & Associates to conduct. According to the analysis, if Arizona develops policies to support a rapid adoption of EVs – reaching one million EVs on the road by 2030 and seven million by 2050 - $31 billion in net economic benefits will be accrued statewide including $9.0 billion to utility customers in the form of reduced electric bills, $15.9 billion to Arizona drivers in the form of reduced annual vehicle operating costs, and $400 million due to the value of reduced nitrogen oxide (NOx) emissions.
- In December 2018, the Arizona Corporation Commission approved an electric vehicle policy that highlights public and ratepayer benefits of transportation electrification; describes opportunities and encourages utilities under its purview to invest in EV infrastructure and programs; and allows utilities to seek cost recovery for prudent investments in charging infrastructure.
- In June 2019, Salt River Project, as part of its 2035 Sustainability Goals, adopted a policy to support the necessary infrastructure to enable at least 500,000 EVs in their service territory and to manage 90% of EV charging through price plans, dispatchable load management, original equipment manufacturer (OEM) integration, connected smart homes, behavioral and other emerging programs by 2035.
- In July 2019, the Arizona Corporation Commission approved an Electric Vehicle Policy Implementation Plan to protect consumers and provide further direction for utilities under its purview on the development of EV infrastructure, pilot programs and associated rates.
- In December 2019, Tucson Electric Power, Arizona Public Service, and UNS Electric jointly filed the required Comprehensive Transportation Electrification Plan for Arizona to the Arizona Corporation Commission. In July 2020, the abovementioned utilities began Phase 2 of their Comprehensive Transportation Electrification Plan for Arizona, which is expected to incorporate broad and diverse stakeholders in a series of workshops and working groups and conclude with proposed next steps for the Arizona Corporation Commission in February 2021.

Prepared By: Diane E. Brown, Executive Director, Arizona PIRG Education Fund: dbrown@arizonapirg.org or (602)318-2779 (c).

SWEEP
SOUTHWEST ENERGY EFFICIENCY PROJECT

WESTERN RESOURCE ADVOCATES
PROTECTING THE WEST'S LAND, AIR, AND WATER

Electric Vehicle Cost-Benefit Analysis

Plug-in Electric Vehicle Cost-Benefit Analysis: Arizona

MJB & A

December 2018

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About M.J. Bradley & Associates

M.J. Bradley & Associates, LLC (MJB&A), founded in 1994, is a strategic consulting firm focused on energy and environmental issues. The firm includes a multi-disciplinary team of experts with backgrounds in economics, law, engineering, and policy. The company works with private companies, public agencies, and non-profit organizations to understand and evaluate environmental regulations and policy, facilitate multi-stakeholder initiatives, shape business strategies, and deploy clean energy technologies.

Our multi-national client base includes electric and natural gas utilities, major transportation fleet operators, clean technology firms, environmental groups and government agencies.

We bring insights to executives, operating managers, and advocates. We help you find opportunity in environmental markets and anticipate and respond smartly to changes in administrative law and policy at federal and state levels. We emphasize both vision and implementation and offer timely access to information along with ideas for using it to the best advantage.

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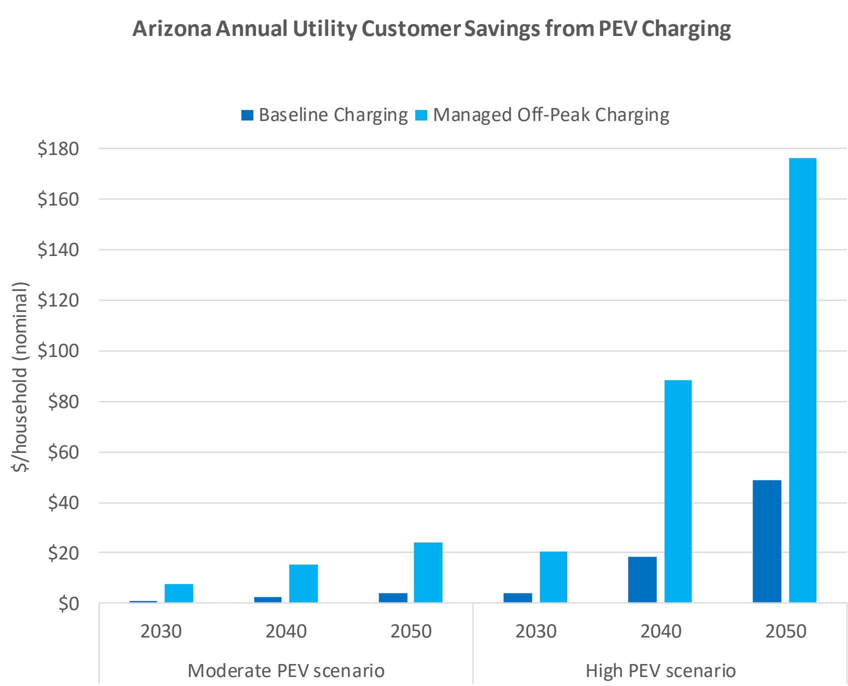
Executive Summary

This study estimated the costs and benefits of increased penetration of plug-in electric vehicles (PEV) in the state of Arizona, for two different penetration scenarios between 2030 and 2050.[1] The "Moderate PEV" scenario is based on the Transportation Electrification Goals in Arizona Corporation Commissioner Andy Tobin's *2018 Draft Energy Modernization Plan*, which includes a state-wide goal of one million PEVs registered in Arizona by 2050. [1] The "High PEV" scenario includes more aggressive PEV penetration levels that would be required to achieve deep reductions in vehicle air pollution emissions.

This study focused on passenger vehicles (cars and light trucks). There are additional opportunities for electrification of non-road equipment and medium- and heavy-duty trucks and buses, but evaluation of these applications was beyond the scope of this study.

The study estimated the benefits that would accrue to all electric utility customers in Arizona due to increased utility revenues from PEV charging. This revenue could be used to support operation and maintenance of the electrical grid, thus reducing the need for future electricity rate increases. These benefits were estimated for a baseline scenario in which Arizona drivers plug in and start to charge their vehicles as soon as they arrive at home or work (baseline charging). The study also evaluated the additional benefits that could be achieved by providing Arizona drivers with price signals or incentives to delay the start of PEV charging until after the daily peak in electricity demand (managed off-peak charging).

Figure 1 Potential Effect of PEV Charging Net Revenue on Arizona Utility Customer Bills (nominal $)



Increased peak hour load increases a utility's cost of providing electricity and may result in the need to upgrade distribution infrastructure. As such, managed off-peak PEV charging can provide net benefits to all utility customers by shifting PEV charging to hours when the grid is underutilized, and the cost of electricity is lower.

[1] PEVs include battery-electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV).

See Figure 1 for a summary of how the projected utility net revenue from PEV charging might affect average residential electricity bills for all Arizona electric utility customers.[2] As shown in the figure, under the High PEV scenario with managed off-peak charging in 2050, the average Arizona household could realize approximately $176 in annual utility bill savings (nominal dollars) due to vehicle electrification.

In addition, the study estimated the annual financial net benefits to Arizona drivers – from net fuel and maintenance cost savings compared to owning gasoline vehicles. When evaluating costs to PEV owners, this study includes the cost of both home and "public" charging infrastructure required to support the modeled levels of PEV penetration. However, while this charging infrastructure represents a cost to PEV owners, it also represents a revenue opportunity for charging station owners by selling charging services. As such, this study includes as a net societal benefit the annual return on the capital that is invested by public charging station owners.

In addition to direct financial benefits to utility customers, PEV owners, and charging station owners, this study also estimates the societal benefits that would result from reduced nitrogen oxide (NOx) and greenhouse gas (GHG) emissions due to vehicle electrification.

As shown in Figure 2 (Moderate PEV scenario), if Arizona meets the transportation electrification goals included in the *2018 Draft Energy Modernization Plan*, the net present value (NPV) of **cumulative net benefits from greater PEV use in Arizona will exceed $3.7 billion state-wide by 2050**.[3] Of these total net benefits:

- At least $200 million will accrue to electric utility customers in the form of reduced electric bills[4],
- $2.6 billion will accrue directly to Arizona drivers in the form of reduced annual vehicle operating costs,
- $500 million will accrue to owners of public charging infrastructure in the state,
- $300 million will accrue to Arizona residents due to reduced costs of complying with future carbon reduction regulations, and
- $70 million will accrue to society at large, as the value of reduced NOx emissions.

As shown in Figure 3 (High PEV scenario), if PEV penetration were even higher - reaching 90 percent of the vehicle fleet in 2050 - the NPV of **cumulative net benefits from greater PEV use in Arizona could exceed $31 billion state-wide by 2050**. Of these total net benefits:

- Up to $9.0 billion will accrue to electric utility customers in the form of reduced electric bills,[5]
- $15.9 billion will accrue directly to Arizona drivers in the form of reduced annual vehicle operating costs,
- $3.9 billion will accrue to owners of public charging infrastructure in the state,
- $2.3 billion will accrue to Arizona residents due to reduced costs of complying with future carbon reduction regulations, and
- $400 million will accrue to society at large, as the value of reduced NOx emissions

[2] Based on 2016 annual average electricity use of 11,075 kWh per housing unit in Arizona.
[3] Using a three percent discount rate.
[4] Figure 2 includes utility customer savings under the baseline charging scenario; savings would be higher under the managed off-peak charging scenario.
[5] Figure 3 includes utility customer savings under the managed off-peak charging scenario; savings would be lower under the baseline charging scenario.

Figure 2 *NPV Cumulative Societal Net Benefits from AZ PEVs – Moderate PEV scenario*

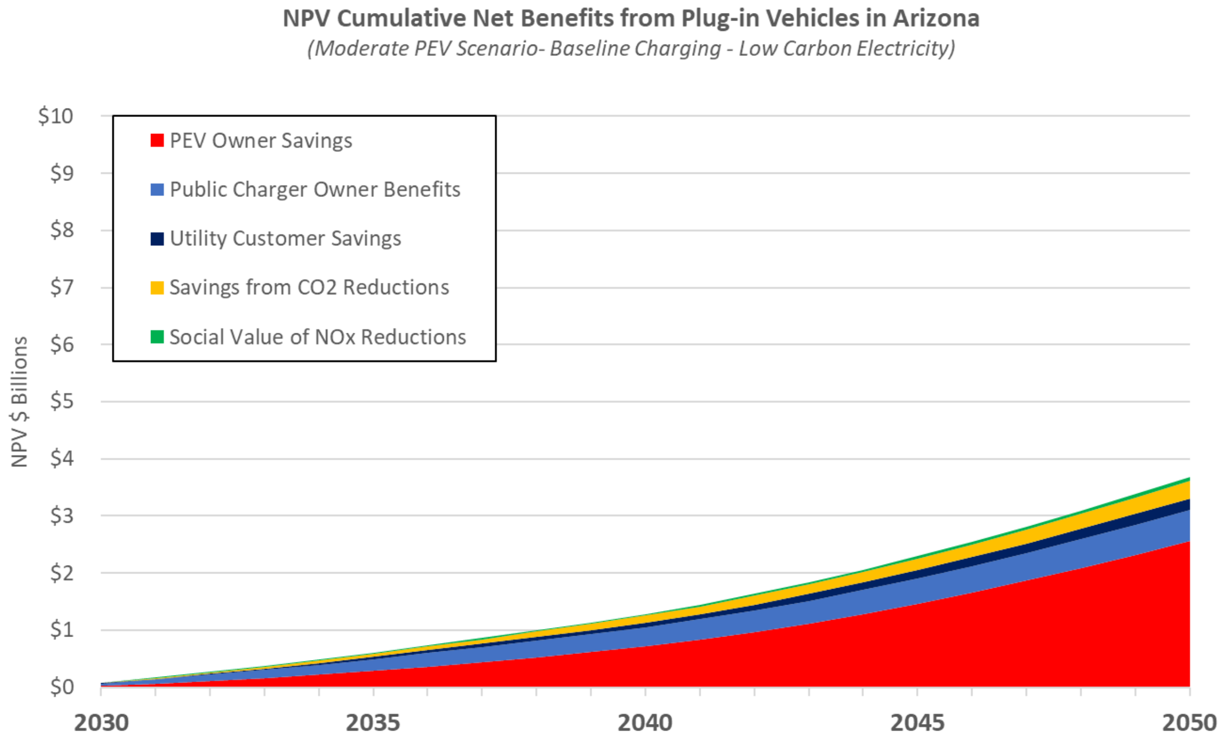
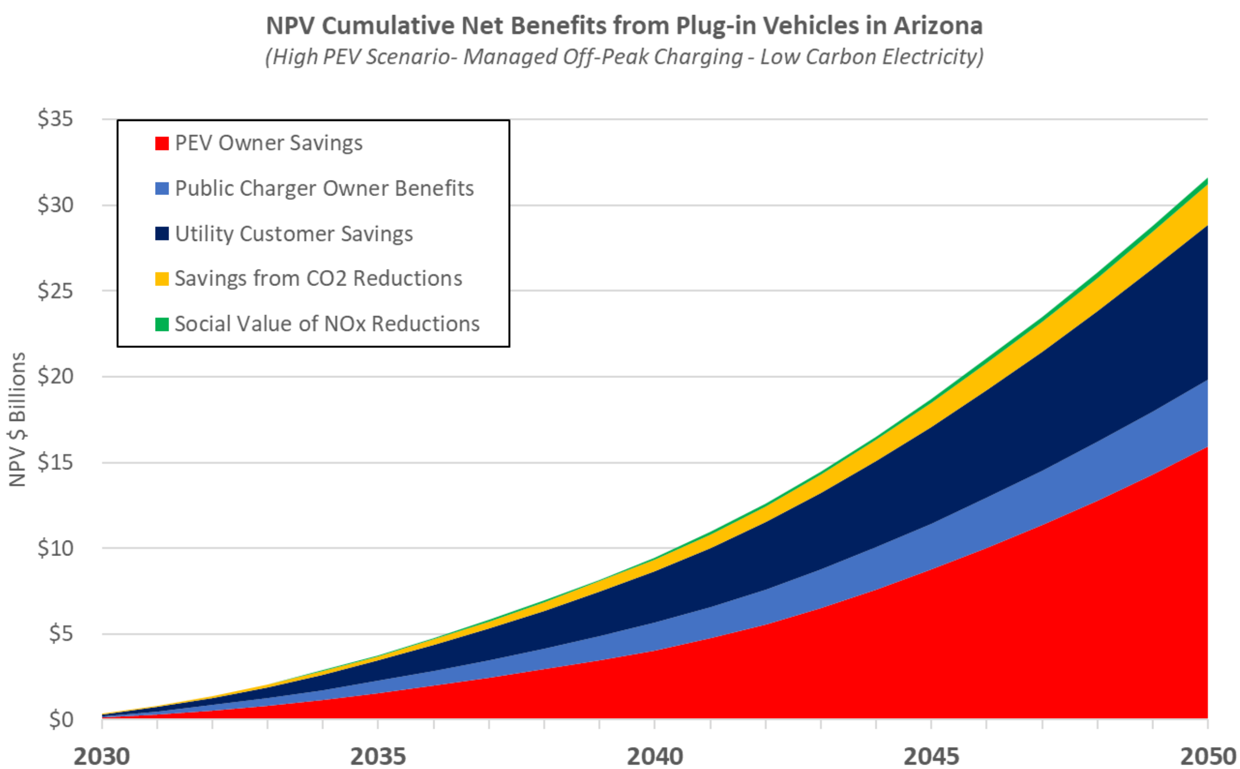


Figure 3 *NPV Cumulative Societal Net Benefits from AZ PEVs – High PEV scenario*



By 2050, PEV owners are projected to save more than $590 per vehicle (nominal $) in annual operating costs, compared to owning gasoline vehicles. A large portion of the direct financial benefit to Arizona drivers derives from reduced gasoline use — from purchase of lower cost, regionally produced electricity instead of gasoline imported to the state. Under the Moderate PEV scenario, PEVs will reduce cumulative gasoline use in the state by more than 2.1 billion gallons through 2050 – this cumulative gasoline savings grows to 15.5 billion gallons through 2050 under the High PEV scenario. In 2050, annual average gasoline savings will be approximately 133 gallons per PEV under the Moderate PEV scenario, while projected savings under the High PEV scenario are 179 gallons per PEV.

This projected gasoline savings will help to promote energy security and independence and will keep more of vehicle owners' money in the local economy, thus generating even greater economic impact. Studies in other states have shown that the switch to PEVs can generate up to $570,000 in additional economic impact for every million dollars of direct savings, resulting in up to 25 additional jobs in the local economy for every 1,000 PEVs in the fleet. [2], [3], [4], [5], [6]

In addition, this reduction in gasoline use will reduce cumulative net greenhouse gas (GHG) emissions by more than 22 million metric tons through 2050 under the Moderate PEV scenario and over 160 million metric tons under the High PEV scenario.[6] The switch from gasoline vehicles to PEVs is also projected to reduce annual NOx emissions in the state by over 377 tons in 2050 under the Moderate PEV scenario and by over 2,900 tons under the High PEV scenario.

[6] Net of emissions from electricity generation

Arizona Statewide Transportation Electrification Plan

December 2019

Energy and Environmental Economics, Inc.
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Energy+Environmental Economics

Executive Summary

Electric vehicle (EV) technology has progressed dramatically in recent years and is beginning to create changes to our conventional transportation system. Transportation electrification (TE) can provide significant benefits to EV purchasers and utility customers generally, improves air quality, and aids in the growth of the Arizona economy. To unlock this value, Arizona's electric utilities, regulatory agencies, policymakers, automakers, third-party charging service providers, and other stakeholders must work together to support EV adoption while also integrating this new load into the existing electricity system. As such in Decision No. 77289, the Arizona Corporation Commission ordered the state's Public Service Corporations (PSCs) to develop a long-term, comprehensive Statewide Transportation Electrification Plan (TE Plan) for Arizona. This strategic plan will provide a roadmap for TE in Arizona, focused on realizing the associated benefits for all residents in the state.

This report constitutes Phase One of a two-part process. Phase One provides a conceptual framework for the Statewide Transportation Electrification Plan for Arizona, including planned or proposed near-term utility actions to support the growth of EVs in the state. Phase Two will build upon this initial roadmap, with input from key stakeholders including non-governmental organizations (NGOs), government agencies and utilities. Phase Two will incorporate in-depth analyses of potential TE opportunities including air quality and economic development opportunities and will develop detailed implementation strategies for utilities and other stakeholders.

This Phase One report:

- Documents the current state of TE technologies and their level of adoption;
- Describes existing policies, programs and initiatives focused on TE;
- Summarizes the perspectives of Arizona stakeholders on TE and the role of electric utilities;
- Discusses the air quality benefits afforded by TE;
- Identifies key barriers and opportunities for developing the TE market in Arizona;
- Proposes near-term actions and initiatives the utilities will take to address barriers to TE development; and
- Outlines the topics of further and stakeholder collaboration to be addressed in Phase Two.

While TE technology has been developing across different segments of the transportation sector, certain transportation modes offer more promising near-term opportunities given their level of technical maturity. Near-term opportunities include electrification of **light-duty vehicles**, **medium-duty parcel vans**, **truck stops**, **transport refrigeration units**, and **nonroad vehicles or equipment**.

In Phase One, a "gaps analysis" of light-duty vehicles was performed to assess near-term opportunities for the electric utilities and other stakeholders to take action in order to realize the benefits of TE. The following table summarizes this analysis, providing select examples of current Arizona Public Service (APS), Tucson Electric Power (TEP) and UNS Electric, Inc. ("UNS Electric") – collectively, the "utilities" – initiatives aimed at overcoming TE barriers to light-duty EVs. The "Addressable Gap" describes how the barrier persists beyond current utility initiatives and can help to inform the utilities' actions as they further develop their TE programs.

Barriers are discussed in further detail in Chapter 2, while detailed descriptions of the full complement of current utility TE initiatives are included in Chapter 5. Chapter 7 provides the full gaps analysis and descriptions of near-term utility actions that will help to address remaining barriers.

Not all of the gaps can be closed – in full or in part – by the utilities alone. Through more intensive engagement with state and local governments and stakeholders in Phase Two, utilities and other participants will identify the need for, and seek the support of, these important partners.

Table 1: Transportation Electrification Gaps Analysis (light-duty vehicles)

Market Barrier	Potential Utility Actions	Current Utility Initiatives (Select Examples)	Addressable Gap
Limited Awareness of EVs	Education & Marketing Electrify utility vehicles	APS participation in EV events TEP Residential EV Calculator	EVs remain outside of most consumers' consideration when purchasing a vehicle
EV Model Availability	None	None	EV models remain largely smaller and/or luxury vehicles (this gap is not directly addressable by utilities)
Upfront Cost Premium	Employee discount programs Engage automakers	TEP planned *Walk the Talk* employee program Nissan LEAF Discount	Upfront cost of EVs deters customers, even when total cost of ownership (TCO) is lower
Lack of Charging Infrastructure & Related Range Anxiety	Deploy additional EV supply equipment (EVSE) (public, workplace, multi-family) Advocate for EV-readiness in building codes	APS *Take Charge AZ* program APS *Charging Siting* analysis TEP *Smart Homes EV* and *Smart Cities EV* programs Maricopa Association of Governments (MAG) EV pre-wiring guidance (from SRP)	Charging infrastructure to address range anxiety and spur EV adoption lags current installations
Rate Design	Design alternate tariffs for EV service providers	APS and TEP plans to introduce DC Fast Charging (DCFC) rates	Demand charges present a challenge for EV service providers at current low utilization rates
Lack of Dealership Incentives	Engage automakers	Nissan LEAF Discount	Conventional light-duty vehicles will remain default choice without additional dealer incentive to sell EVs

Grid Integration Challenge	Potential Utility Actions	Current Utility Initiatives (Select Examples)	Addressable Gap
Distribution Impacts and Upgrade Costs	Expand EV TOU rate options EV service provider infrastructure buildout in low-cost locations Pilot programs to understand grid impacts	TEP EV TOU discount and planned EV-specific TOU rates APS TOU rates APS proposed *Demand Management for EV Charging* pilot program	The need to manage charging will become more acute as EV loads grow; without active planning upgrade costs will be high
Integration of Renewables	Support and enable expanded workplace charging	APS *Take Charge AZ* program TEP *Smart Cities EV* program	Most EV charging currently takes place at home and is poorly aligned with the timing of renewable generation

As demonstrated by the select example initiatives in Table 1, the utilities are already running programs that are aimed at addressing many of these barriers. In Phase Two the utilities will focus their efforts on expanding the programs that are most effectively addressing these key barriers, including conducting cost-benefit analyses and other research initiatives, establishing goals and metrics for evaluating success, engaging stakeholders to ensure that their initiatives are helping to develop TE in Arizona in a way that meets the needs of a broad and representative range of residents, and collaborating with state and local agencies to maximize programmatic impacts. Figure 1 provides an overview of the two project phases.

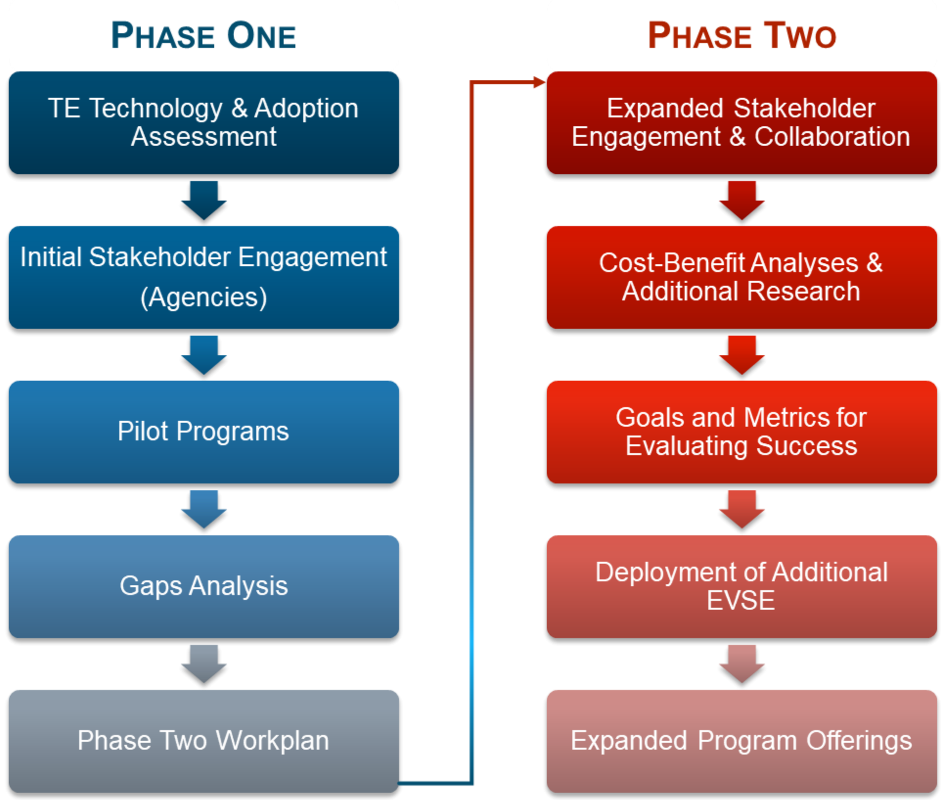

Figure 1: Phases One and Two of the Strategic Transportation Electrification Plan

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1) Introduction

Long perceived as a technology of the future, electric vehicles (EVs) have entered the mainstream and are rapidly becoming an important component of the modern transportation system. Automakers offer dozens of models today and will release an increasing variety of options over the next several years, as detailed in Figure 2 below.

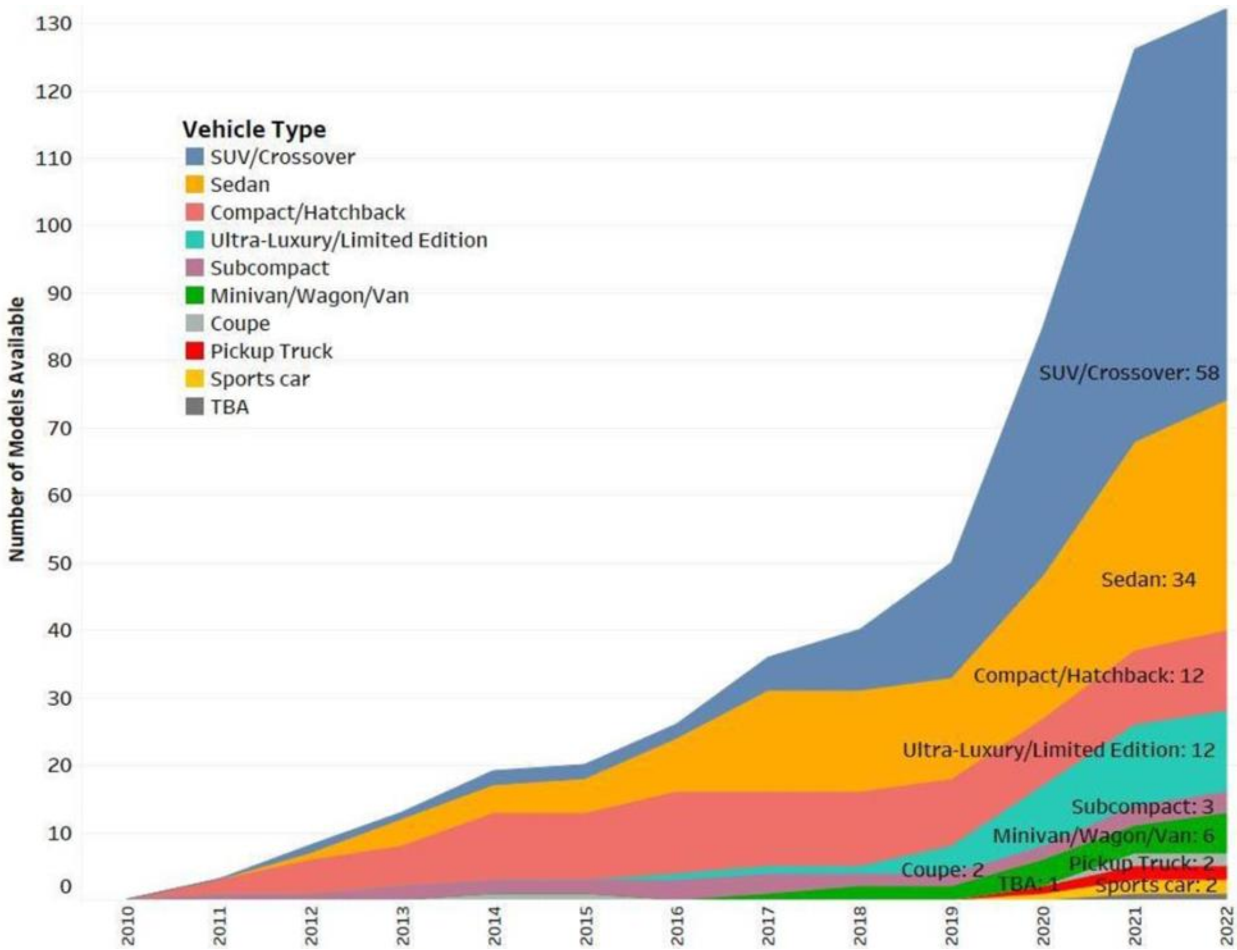

Figure 2: Count of EV models available or announced, 2010 – 2022[1]

With proper planning and integration, transportation electrification (TE) offers widespread opportunities for EV driver and utility customer savings, air quality improvements, increased mobility choices and economic development. Given the scale of this potential shift in the transportation sector, however, achieving these benefits requires coordinated action between numerous players including electric utilities, regulatory agencies, policymakers, automakers and third-party charging service providers, among others. This report – Phase One of a two-part process – aims to provide an important starting point for

[1] Electric Power Research Institute, “Overview of EV Market and PHEV Technology,” July 8, 2019.

this coordination effort by outlining key areas of opportunity in Arizona as well as barriers to achieving them, and by describing the initial actions Arizona Public Service (APS) and Tucson Electric Power (TEP and UNS Electric, Inc. ("UNS Electric") are taking to realize the benefits of TE. Phase Two will build upon this initial roadmap, incorporating in-depth analyses of potential TE opportunities and developing detailed implementation strategies for utility initiatives. Phase Two is discussed in further detail in Chapter 8.

The Opportunity

Transportation electrification can provide numerous benefits to EV drivers, utility customers, and the Arizona economy overall. Residents adopting an EV can save on fuel and maintenance costs, utility customers can benefit from increased utilization of utility assets. EVs would replace internal combustion engines (ICE), thereby reducing emissions of harmful air pollution, directly benefiting the health of all Arizonans. Additionally, the emergent TE industry, which is already bringing investment and new jobs to the state, would help to grow Arizona's economy. For example, automaker Lucid Motors recently broke ground on its EV manufacturing facility in Casa Grande, which is projected to provide 4,800 direct and indirect jobs in the next decade and $32 billion in local revenue impacts over the next 20 years.[2]

Arizona Corporation Commission TE Policy and Directive

Over the past two years the Arizona Corporation Commission (ACC or Commission) has been considering TE and the role of the electric utilities in this area. In November 2018 the Commission Utilities Division Staff (Staff) was directed to develop a *Policy Statement on Electric Vehicles, EV Infrastructure, and the Electrification of the Transportation Sector in Arizona* (EV Policy). Staff developed the requested policy statement, informed in part through discussions with stakeholders at two meetings held in late 2018; the policy was formally adopted by the Commission in January 2019.[3] The EV Policy addressed key TE-related topics and questions, encouraged the utilities to invest in infrastructure and programs to support EV charging and encourage widespread adoption of TE, and directed Commission Staff to develop an implementation plan for the policy statement.

Through continued discussions with stakeholders at two additional workshops (held in March 2019) and in written comments filed in the docket,[4] the *ACC Staff Implementation Plan for the Electric Vehicles, Electric Vehicle Infrastructure, and the Electrification of the Transportation Sector in Arizona Policy Statement* (Plan or Commission Plan) was adopted by the ACC in July 2019.[5] This Plan provides guidelines to the utilities as to how best to implement the Commission's EV Policy, including direction on development of pilot programs, EV rate design, cost recovery of TE investments, education and outreach activities, charging station siting and infrastructure development, and periodic reporting on TE activities. This plan also directs the utilities to develop a "joint, long-term, comprehensive transportation electrification plan for Arizona" by December 31, 2019. This Phase One report constitutes the utilities'

[2] TechCrunch, "Lucid Motors breaks ground on its $700 million Arizona factory," December 2, 2019. Available at: https://techcrunch.com/2019/12/02/lucid-motors-breaks-ground-on-its-700-million-arizona-factory/.

[3] Arizona Corporation Commission, "Decision No.77044," January 16, 2019.

[4] RU-0000A-18-0284.

[5] Arizona Corporation Commission, "Decision No. 77289," July 19, 2019.

plan, which will be further developed with additional detail and supporting analysis in Phase Two beginning in early 2020.

Approaches to Developing TE Strategic Plans

A TE strategic plan will provide the roadmap to cost-effective, beneficial electrification of transportation in Arizona. Several states have started down this road and have taken different approaches to planning for TE. Energy regulators in some states have directed utilities to develop comprehensive plans or portfolios of pilot programs. Some state governments have also, or instead, developed strategic plans that focus on how state agencies should work together and with utilities and other stakeholders to promote TE. In blazing its own trail Arizona can draw upon the paths other states have followed.

The scope of Commission driven plans and the extent of regulators' involvement in their development has varied, as illustrated by the following examples:

- The Hawaiian Electric Company (HECO), at the direction of the Hawai'i Public Utilities Commission (HPUC), developed a comprehensive, long term strategic roadmap. The roadmap lays out HECO's planned TE initiatives over the next decade for light, medium and heavy-duty vehicles, and equipment at airports, seaports and military bases. Since HECO serves all of Hawaii's main populated islands except Kauai, it is practically a statewide plan. It focuses on HECO's plans, but also identifies complementary roles and actions for government and other stakeholders. In developing the roadmap HECO engaged a wide range of stakeholders including state and local governments, automakers, auto dealerships, electric vehicle service providers (EVSPs), transportation network companies (TNCs), environmental groups, consumer advocates, the military and the University of Hawai'i. HECO submitted its Electrification of Transportation Strategic Roadmap to the Commission in March 2018.[6] The HPUC took public comment on the plan and has since provided direction to HPUC on its priorities for implementation.[7]
- The Maryland Public Service Commission charged a stakeholder group, the EV Work Group, with developing a coordinated statewide approach to EV rates, deploying electric vehicle supply equipment (EVSE), managing grid impacts, and electrifying fleets. The process culminated in a filing by Maryland's four investor owned utilities (IOUs) and numerous stakeholders requesting Commission approval of a proposed EV Portfolio, which focused mainly on rate design and utility investments in EV charging infrastructure for light-duty vehicles (LDVs). In 2019 the Maryland Public Service Commission eventually approved scaled down versions of each utility's proposed EV Portfolio, and the utilities are now implementing the authorized programs.[8] More recently Governor Hogan enlisted the National Governors Association (which he chairs) to convene state agencies, utilities and key stakeholders to examine the full spectrum of TE opportunities in Maryland.

[6] Hawaiian Electric Companies, "Electrification of Transportation Strategic Roadmap," March 2018. Available at: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/electrification_of_transportation/201803_eot_roadmap.pdf.

[7] Hawaii Public Utilities Commission, "Order No. 36448," July 31, 2019. Available at: https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A19H01B00118I00099.

[8] Maryland Public Service Commission, "Order No. 88997," January 14, 2019. Available at: https://www.psc.state.md.us/wp-content/uploads/Order-No.-88997-Case-No.-9478-EV-Portfolio-Order.pdf.

- The Michigan Public Service Commission oversaw a stakeholder process that resulted in proposals for utility pilots that DTE and Consumers Energy then rolled into rate cases. In a pair of technical workshops, the Michigan Public Service Commission sought input from stakeholders on priorities for utility programs and then provided guidance to the utilities.[9,10] As in Maryland, the emphasis was on rates and charging infrastructure for light duty vehicles.
- Although California leads the nation in TE the California Public Utility Commission (CPUC) has yet to provide detailed direction to its jurisdictional utilities: it has authorized over a billion dollars in ratepayer funding for utility TE initiatives on a case-by-case basis. Change is afoot, however. In late 2018 the CPUC opened a new rulemaking to examined lessons learned from the initial rounds of utility programs and to consider requiring the utilities to develop strategic plans.[11] The CPUC plans to release a draft *Transportation Electrification Framework* for stakeholder comment before the end of 2019. The framework is intended "to establish a common and comprehensive framework for IOU investments in TE in California, aligned with" legislative direction and "will help guide the next chapter of policies and programs supporting California's [Zero Emission Vehicle (ZEV)] infrastructure."[12]

California and Colorado provide examples of states that have developed strategic plans that focus on how state agencies should work together to promote TE. The 2018 Colorado Electric Vehicle Plan focuses on the state's efforts to deploy public charging infrastructure, especially along major corridors.[13] Starting in 2013, the California Governor's Office of Business Development has facilitated collaborative interagency efforts to develop and update and expansive statewide ZEV Acton Plan that describes the role of leading and supporting state agencies in implementing the state's TE initiatives across all sectors of goods and people movement.[14]

These examples of different approaches to strategic TE planning can help to guide Arizona as it expands its own efforts in this area.

Report Overview

This Phase One report outlines the current state of TE technology, discusses the key barriers to adoption, provides an overview of Arizona-specific context including key policies and stakeholder perspectives, and describes the remaining gaps to be addressed in order to unlock the benefits of TE in the state. Phase Two

[9] Michigan Public Service Commission, "Order Adopting Guiding Principles and Commencing a Second Collaborative Technical Conference," December 20, 2017. Available at: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001X2MFAA0.

[10] Michigan Public Service Commission, "Order Following the Second Collaborative Technical Conference," March 29, 2018. Available at: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000002286rAAA

[11] California Public Utilities Commission, "Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification and Closing Rulemaking 13-11-007," December 19, 2018. Available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M252/K025/252025566.PDF.

[12] Ibid.

[13] Colorado Energy Office, "Colorado Electric Vehicle Plan," January 2018. Available at: https://www.colorado.gov/pacific/energyoffice/atom/162026.

[14] See: http://www.business.ca.gov/ZEV-Action-Plan for history of the planning process and links to the 2016 Plan and 2018 Update.

will be to further develop the strategic Statewide Transportation Electrification Plan, focusing on the areas of near-term opportunity discussed in this report.

The report is structured as follows:

- Chapter 2 provides an overview of the status of transportation electrification technologies and the primary barriers to adoption, highlighting near-term opportunities.
- Chapter 3 describes the federal, state and local TE policies and initiatives that shape the legal and regulatory landscape for EVs.
- Chapter 4 summarizes the primary issues of interest to different TE stakeholders in Arizona, describing areas of agreement as well as ongoing challenges.
- Chapter 5 details the various programs and initiatives that APS and TEP currently offering or developing in support of TE.
- Chapter 6 briefly describes the scale of TE opportunities in Arizona.
- Chapter 7 provides an assessment of how well the current utility initiatives are addressing the primary barriers to TE, highlighting gaps that if unaddressed will limit uptake of these technologies.
- Chapter 8 outlines the primary actions that the utilities will undertake in Phase Two in order to further develop the strategic Statewide Transportation Electrification Plan.

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This report has been developed in collaboration with *Energy and Environmental Economics, Inc.* (E3), an energy consulting firm with expertise in the economics and public policy of TE and extensive experience supporting utility strategic planning for TE.

AchiEVe:

Model Policies to Accelerate Electric Vehicle Adoption

Presented by the Sierra Club, Plug In America, FORTH, and the Electrification Coalition

Version 4.0, August 2020

ACKNOWLEDGMENTS

The original report was written by the Sierra Club's Mary Lunetta and Plug In America's Katherine Stainken in 2017. This 4.0 version was updated and edited by Plug In America's Katherine Stainken; the Sierra Club's Hieu Le; Forth's Jeanette Shaw, Kelly Yearick, Tegan Molloy, and Jeff Allen; and the Electrification Coalition's Sue Gander, Ben Prochazka, Will Drier, Andrew Bin, Alissa Burger, Brad Nelson, and Andrew Linhardt. Editing assistance has been provided by the Sierra Club's Gina Coplon-Newfield, Larisa Mănescu, and Morgan Ellis. Report was designed by the Sierra Club.

Román Partida-López from Greenlining Institute reviewed this report.

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PHOTO CREDIT THIS PAGE: OKSANAPHOTO

INTRODUCTION

The transportation sector in the US is the leading source of greenhouse gas emissions in our country and is 92 percent dependent on oil. In addition to contributing to the climate crisis, emissions from our fossil fuel-powered cars, trucks, and buses are making our air unsafe to breathe. Too many people for too long, particularly in low-income neighborhoods and communities of color, have borne the brunt of air pollution and a lack of access to clean and accessible transportation options. The status quo of our transportation systems is threatening our health, our climate, the well-being of our communities, and our national security.

In order to combat our climate crisis, improve air quality and public health, and improve our energy security, we must move transportation away from oil and toward an electric future. Electrifying transportation is a solution that makes sense. Policymakers must prepare for this major shift in how transportation is fueled by implementing bold policies that will accelerate this transformation to plug-in electric vehicles (EVs). This toolkit is designed to provide public officials and advocates with model EV policies that accelerate the switch to these clean vehicles in an effective, sustainable, and equitable way.

EVs on the market today are high-performing, technologically advanced, quiet, and significantly lower in emissions compared to fossil fuel powered vehicles, even when factoring in total lifecycle emissions and the emissions from the electricity used to charge them. As we shift to more renewable sources of power, EVs become even cleaner over time. This is great news for public health and climate protection. The burgeoning EV market is also an opportunity for states to work with automakers to develop new regional economic development opportunities—both for vehicle manufacturing and for components further up the supply chain. Managing this transition and creating localized supply chains will be critical for the many autoworkers in the US whose jobs depend on being a part of the electric future of transportation.

The COVID-19 crisis has had major implications for not just the health of communities across the country but also the US economy, exposing and exacerbating long-standing inequities, including within our transportation systems. As we seek to rebuild our economy, we must do so equitably, leaving no person and no community behind. Investment in clean transportation — with a particular focus on public transit and electrification of cars, trucks, and buses — is a significant step toward building that future.

Decision-makers often want to know the best policies to accelerate this adoption. In this toolkit, we have compiled guidance on how to approach EV policies, and we have provided links to actual policies across a range of categories that are currently enacted at the state, local, and utility levels. In this toolkit, we compiled guidance on how to approach EV policies, we provide over 50 policies across a range of categories currently enacted at the state, local, and utility levels.

The charts below show which policies are most relevant for each audience. We encourage policymakers, regulators, and businesses to read through each of the policies relevant to the type of decision-maker and to work toward implementing a comprehensive set of measures to accelerate EV adoption.

GOVERNORS' OFFICES, STATE AGENCIES

LEGISLATORS

REGULATORS/UTILITIES

TRANSIT AGENCIES

286

CITIES/LOCAL GOVERNMENTS

BUSINESSES

ACRONYMS

AFV: Alternative Fueled Vehicle

BEV: Battery Electric Vehicle

EV: Electric Vehicle

EVSE: Electric Vehicle Supply Equipment

HEV: Hybrid Electric Vehicle

HOV: High-Occupancy Vehicle

NGO: Nongovernment Organization

MUD: Multiunit Dwelling

PEV: Plug-in Electric Vehicle

PHEV: Plug-in Hybrid Electric Vehicle

ZEB: Zero-Emission Bus

ZEV: Zero-Emission Vehicle

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The Office of Arizona Governor Doug Ducey
1700 W. Washington Street
Phoenix, AZ 85007

June 15, 2020

RE: Leveraging the Transportation Electrification Industry for Arizona's Economic & Public Health Gain

Dear Governor Ducey,

On behalf of the following organizations, we urge you to lead Arizona to an electric transportation future. **Accelerating the shift to electric transportation will significantly benefit Arizona's economic recovery while also improving air quality and public health.**

Automakers have invested billions of dollars into this sector and remain committed to an electric transportation future.[1] Implementing strong policies that accelerate the transition to an electrified transportation sector will create thousands of additional technology and innovation jobs in our state, as Arizona is quickly becoming a hotspot for electric vehicle (EV) innovation and enterprise. As you are aware, companies such as Lucid Motors and Nikola Motors are now headquartered in Arizona, with the Lucid Motors manufacturing plant in Casa Grande expected to create approximately 4,800 direct and indirect jobs by 2029.[2] Furthermore, Waymo is conducting cutting edge research in the East Valley of Maricopa County on the future of autonomous vehicles. Implementing supportive policies to install EV charging infrastructure also has the potential to create thousands of shovel-ready jobs for Arizonans.

Arizonans could use additional dollars in their pockets; dollars that can also be invested back into local economies and the small businesses that have been severely impacted by the pandemic. On average, EVs save consumers and fleet operators about $770 a year in fuel costs per vehicle.[3] In addition to the fuel cost savings, these vehicles also have low maintenance costs. EVs are quickly becoming a win-win for consumers and businesses, even with the current low gas prices.[4] Electric buses have been shown to save more than $400,000 in fuel costs and $125,000 in averted maintenance costs over the lifetime of the electric bus compared to a traditional diesel bus, making electric buses a win-win as well.[5]

An accelerated transition to an electric transportation future will help recover Arizona's economy and promote public health and improve the air that Arizonans breathe. Pollution from vehicle tailpipes is the single largest contributor to Arizona's air pollution.[6] Early studies indicate that air pollution can be linked to increased respiratory and heart issues; for example, the Harvard T.H. Chan School of Public Health study showed that small increases in long-term particulate matter exposure are associated with increases in the COVID-19 death rate.[7]

[1] For example, recent investment and jobs announcements include: Volvo to build Charleston-area battery plant to power SC-made vehicles https://www.postandcourier.com/business/volvo-to-build-charleston-area-battery-plant-to-power-sc/article_c44113a4-33cd-11ea-a049-5f0cafb689af.html; GM investing $3 billion to produce all-electric trucks https://www.cnbc.com/2020/01/27/gm-investing-3-billion-to-produce-all-electric-trucks.html; Rivian invests $29.4 million in Normal facility https://www.pantagraph.com/news/local/rivian-invests-million-in-normal-facility/article_cd4f0392-e955-5f1d-86c2-ed2d0f24b086.html; Volkswagen invests at least $800 million in Chattanooga to build EVs https://www.timesfreepress.com/news/business/story/2019/oct/19/chattanooga-volkswagen-electric-vehicles/506026/; GM partnered with LG Chem in a $2.3 billion joint venture to manufacture batteries for PEVs https://www.cnbc.com/2019/12/07/gm-lg-venture-adds-to-multibillion-dollar-partnerships-on-evs-avs.html

[2] Lucid Motors, "Lucid Motors Marks Start of Construction at Arizona Electric Vehicle Factory Site", 2019. [Online]. Available: https://lucidmotors.com/media-room/lucid-motors-marks-start-construction-arizona-electric-vehicle-factory-site. [Accessed May 2020].

[3] Union of Concerned Scientists, "Going from Pump to Plug: Adding Up the Savings from Electric Vehicles (EVs)", 2017. [Online]. Available: https://www.ucsusa.org/resources/going-pump-plug. [Accessed May 2020].

[4] U.S. Department of Energy, "Saving on Fuel and Vehicle Costs". [Online]. Available: https://www.energy.gov/eere/electricvehicles/saving-fuel-and-vehicle-costs. [Accessed May 2020].

[5] Arizona PIRG Education Fund, "Electric Buses in America Lessons from Cities Pioneering Clean Transportation", 2019. [Online]. Available: https://arizonapirgedfund.org/sites/pirg/files/reports/Electric%20Buses%20Report%2010-19.pdf. [Accessed May 2020].

[6] Union of Concerned Scientists, "Cars, Trucks, Buses and Air Pollution Transportation is a major source of air pollution in the United States", 2018. [Online]. Available: https://www.ucsusa.org/resources/cars-trucks-buses-and-air-pollution. [Accessed May 2020].

[7] Harvard TH Chan School of Public Health, "Air pollution linked with higher COVID-19 death rates", 2020. [Online]. Available: https://www.hsph.harvard.edu/news/hsph-in-the-news/air-pollution-linked-with-higher-covid-19-death-rates/. [Accessed May 2020].

Furthermore, people of color are being disproportionately impacted by COVID-19 and are most often those exposed to greater air pollution.[8]

In terms of the quality of the air Arizonans breathe, the American Lung Association "State of the Air 2020" report, released April 21, 2020, grades and ranks every county and city based on ozone and particle pollution monitoring data.[9] This year, the study found that out of the 12 counties in Arizona with air pollution monitors, 11 counties scored a "C" or worse, representing nearly 7 million residents. The Phoenix-Mesa metropolitan area was ranked 7th worst in the nation for ozone and year-round particle pollution, while it ranked 10th worst for short-term particle pollution. Arizona can, and must, do better. Electric transportation technologies have no tailpipe pollution and, therefore, will greatly benefit the air Arizonans breathe. These compelling reasons indicate that now is the time to pursue an electric transportation future.

Therefore, we urge that the following policies be adopted in any recovery package to get Arizona back on track:

1. **<u>Lead by example in the transition to transportation electrification:</u>**
    a. Issue an Executive Order stating that purchases of new vehicles in state fleets must prioritize EVs. Through the Arizona Dept. of Administration, establish and encourage joint purchasing for other governmental entities such as municipalities and school districts.
    b. Issue an Executive Order stating purchases of new buses paid with state funding must prioritize electric technology.

2. **<u>Create shovel-ready jobs by accelerating EV infrastructure policies:</u>**
    Enact a streamlined permitting process for public EV charging stations and accelerate job creation in the installation of EV charging stations.

3. **<u>Pave the way for easier consumer adoption of Light Duty EVs and Medium-Duty to Heavy-Duty electric fleets:</u>**
    a. Encourage the state agencies, cities and communities throughout Arizona to adopt EV readiness plans, which include light passenger vehicles, medium-duty and heavy-duty electric fleets, and school bus electrification transition plans, as well as coordinate with regional transportation plans and metropolitan planning organizations.
    b. Ensure that fair registration fees are enacted for EV and electrified freight drivers.

[8] American Lung Association, "Disparities in the Impact of Air Pollution", 2020. [Online]. Available: https://www.lung.org/clean-air/outdoors/who-is-at-risk/disparities. [Accessed May 2020].

[9] American Lung Association, "State of the Air: Arizona", 2020. [Online]. Available: http://www.stateoftheair.org/city-rankings/states/arizona/. [Accessed May 2020].

c. Encourage collaborative program development for transportation electrification between the private sector, utilities supporting charging infrastructure incentives and state agency grant programs such as CMAQ and the Volkswagen Settlement Program that offer funding offsets for electrified vehicle purchases and support charging infrastructure.

We look forward to working with you on all matters related to transportation electrification. Please feel free to contact Katherine Stainken with Plug-In America (kstainken@pluginamerica.org), Diane E. Brown with the Arizona PIRG Education Fund (dbrown@arizonapirg.org), and/or Caryn Potter with the Southwest Energy Efficiency Project (cpotter@swenergy.org) with questions or to discuss the recommendations with yourself or a member of your staff.

Best regards,

Alliance for Transportation Electrification
Alliance of Nurses for Healthy Environments
American Lung Association
Arizona Asthma Coalition
Arizona Center for Law and the Public Interest
Arizona Interfaith Power and Light
Arizona PIRG (Arizona Public Interest Research Group) Education Fund
Arizona Public Health Association
Arizona Thoracic Society
CALSTART
Ceres
ChargePoint
Consumer Federation of America
Elders Climate Action - Arizona Chapter
Electric Auto Association, Phoenix Chapter
Energy Management
EVBox
EVGo
Physicians for Social Responsibility of Arizona
Plug In America
Prescott Electric Vehicle Association
Siemens
Sierra Club
Solar United Neighbors
Southwest Energy Efficiency Project
Tucson Electric Vehicle Association
UU Justice Committee
Vote Solar
Western Grid Group
Western Resource Advocates
Wildfire: Igniting Community Action to End Poverty in Arizona

Arizona PIRG Education Fund
130 N. Central Ave., Ste. 202 | Phoenix, AZ 85004
www.arizonapirgedfund.org (602) 252-9227 (ph)

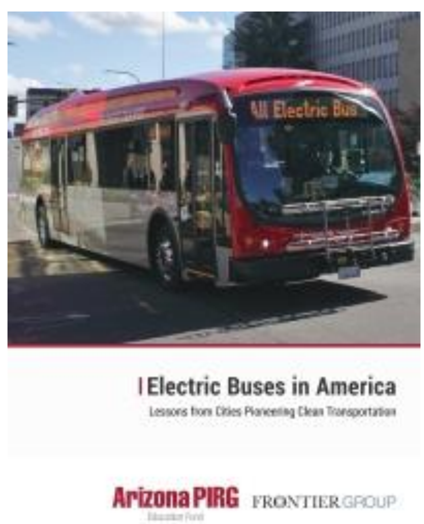
Electric Buses Deliver Numerous Benefits

By eliminating diesel exhaust emissions, particulate pollution and pollutants that contribute to the formation of ground-level ozone, electric buses improve air quality and public health. Electric buses can also deliver financial benefits, including substantially reduced maintenance costs and, in places where utility rate policies are favorable, reduced fuel costs.

For more information, please read our recent reports on electric buses or contact us at info@arizonapirg.org

Electric Buses in America: Lessons from Cities Pioneering Clean Transportation

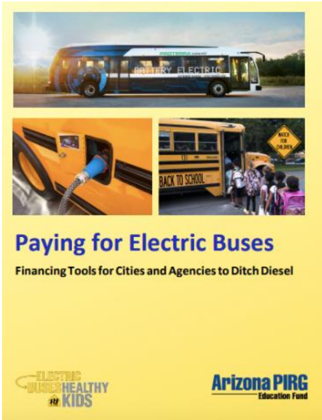
October 2019



Electric Buses in America: Lessons from Cities Pioneering Clean Transportation profiles six case studies of early electric bus adopters from South Carolina to Washington State. The report includes common pitfalls and best practices to help municipalities, transit agencies and school districts reduce costs, protect public health and ensure a smooth roll-out of electric buses.

Paying for Electric Buses: Financing Tools for Cities and Agencies to Ditch Diesel

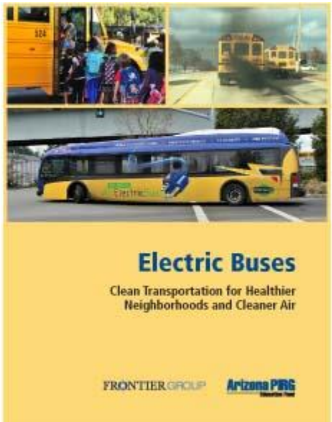
October 2018



Paying for Electric Buses: Financing Tools for Cities and Agencies to Ditch Diesel notes that the upfront purchase price of electric buses is often cited as a hurdle to a swift transition. The report reviews available financing and funding options to make the transition to electric buses more feasible.

Electric Buses: Clean Transportation for Healthier Neighborhoods and Cleaner Air

May 2018



Electric Buses: Clean Transportation for Healthier Neighborhoods and Cleaner Air notes that buses play a key role in our nation's transportation system, carrying millions of children daily to and from school and moving millions of Americans each day around our municipalities. The report notes air quality, public health and financial benefits from shifting to electric buses.

Plug In America

Electric Vehicle Guide

Compare vehicles online at PlugStar.com

All Electric Vehicles

sorted by electric range

Tesla Model S
Starting at **$78,000**
285–370 miles

Tesla Model X
Starting at **$83,000**
250–325 miles

Tesla Model 3
Starting at **$39,900**
240–310 miles

Hyundai Kona Electric
$36,950
258 miles

Kia Niro EV
$38,500
239 miles

Chevrolet Bolt EV
$36,620
238 miles

Jaguar I-PACE
$69,500
234 miles

Nissan LEAF
Starting at **$29,990**
150–226 miles

Audi e-tron
$74,800
204 miles

BMW i3
$44,450
153 miles

Volkswagen e-Golf
$31,895
125 miles

Hyundai Ioniq Electric
$30,315
124 miles

Kia Soul EV
$33,950
111 miles

Honda Clarity Electric
$199/mo. lease only
89 miles

Fiat 500e
$32,995
84 miles

Smart EQ fortwo
$23,900
58 miles

Plug-In Hybrid Vehicles Inside ›

Plug-In Hybrid Vehicles

sorted by electric range

Plug In America

BMW i3 REX
$48,300
153 / **200**
electric total miles

Chevrolet Volt
$33,520
53 / **420**
electric total miles

Honda Clarity Plug-In
$33,400
48 / **340**
electric total miles

Chrysler Pacifica Hybrid
$39,995
32 / **520**
electric total miles

Cadillac CT6 Plug-In
$75,095
31 / **430**
electric total miles

Hyundai Ioniq Plug-In
$25,350
29 / **630**
electric total miles

Kia Optima Plug-In
$35,390
29 / **610**
electric total miles

Ford Fusion Energi
$34,595
26 / **610**
electric total miles

Kia Niro Plug-In
$28,500
26 / **560**
electric total miles

Toyota Prius Prime
$27,350
25 / **640**
electric total miles

Mitsubishi Outlander
$34,595
22 / **310**
electric total miles

Volvo S90 T8 Plug-In
$63,900
21 / **490**
electric total miles

Volvo XC90 T8 Plug-In
$67,000
19 / **380**
electric total miles

Volvo XC60 T8 Plug-In
$55,300
18 / **370**
electric total miles

BMW i8
$147,500
18 / **320**
electric total miles

This guide includes vehicles available as of June 2019. All prices are MSRP. Models, MSRP, and range numbers are subject to change. Vehicle charging rates vary by vehicle and conditions. Visit **PlugStar.com** or your local dealer for updated information.

Plug In America

Plug-In Hybrid Vehicles

sorted by electric range

Subaru Crosstrek Hybrid
$34,995
17 / 480
electric / total miles

Porsche Panamera E-Hybrid
$102,900
16 / 480
electric / total miles

Audi A3 e-tron
$39,500
16 / 400
electric / total miles

BMW 530e
$53,400
16 / 370
electric / total miles

Porsche Cayenne E-Hybrid
$79,900
14 / 490
electric / total miles

BMW 330e
$45,600
14 / 350
electric / total miles

Mini Cooper Countryman
$36,900
12 / 270
electric / total miles

Mercedes GLE 550e
$66,700
10 / 460
electric / total miles

Mercedes GLC 350e
$50,650
9 / 410
electric / total miles

We make driving electric easy!

PlugStar by Plug In America

PlugStar.com

Visit PlugStar.com to find a plug-in vehicle, learn about tax credits and other incentives, get equipped for charging, and connect with a PlugStar-certified dealer in your area!

EV Support Program

EV experts answer your questions about vehicles, charging, incentives, and more!
support@pluginamerica.org
1 (877) EV-HELP-1

PlugInAmerica.org
PlugStar.com

EV Charging 101

LEVEL 1 STANDARD OUTLET

- Plug into a standard 120V wall outlet
- Connector provided with every EV
- Great for overnight or workplace charging
- Ideal for typical commutes (up to 40 miles)

40 miles overnight

LEVEL 2 240 VOLT OUTLET

- Faster charging for longer drives
- Provides a full charge for most EVs in:

100% Electric — **4-8 hours** empty to full charge

Electric & Gas — **1-2 hours** empty to full charge

25 miles per hour of charging

DC FAST CHARGE

- Much faster charging at public locations
- 3 different connectors depending on vehicle:

CCS Combo — **65 miles** in 20 minutes

CHAdeMO — **67 miles** in 30 minutes

Tesla Supercharger — **130+ miles** in 20 minutes

0 to 80% 30-40 minutes

Plug In America
We drive electric. You can too.

The voice of the EV driver

Founded in 2008, Plug In America is a nonprofit organization serving and representing EV drivers.

- We fight for pro-EV policies, including tax credits and access to HOV lanes. Join our network to take action!
- We present National Drive Electric Week and Drive Electric Earth Day for first-hand EV experiences.
- Our PlugStar EV Shopping Assistant and EV Support Program make it easy for drivers to switch to clean EVs.

Join the movement at PlugInAmerica.org

@PlugInAmerica

PlugStar.com • DriveElectricWeek.org • DriveElectricEarthDay.org

Consumer Impacts & Public Participation

Consumer Impacts & Public Participation

As Arizona moves to a more energy-efficient and cleaner energy future, costs and benefits to consumers will undoubtedly be a central part of the discussion. Policymakers need to be cognizant of return on investments and act with both short-and-long-term implications in mind. For example, externalities such as employment potential, air quality improvements, public health gains, water savings, and economic advancements contribute to the clean energy factors that positively impact consumers' pocketbooks. And, along the way, policymakers need to listen to stakeholders and consumers who often provide valuable data and information, and diverse experiences and perspectives.

Here are 10 recommendations for policymakers to promote energy bill savings and provide robust and meaningful opportunities for public participation:

1. Ensure communication presented to consumers is understandable and avoids jargon. For example, the U.S. Energy Information Administration's glossary offers short definitions to help individuals navigate energy terms and videos on Salt River Project's 2035 Sustainability Goals provide relatable information.

2. Offer opportunities for Arizonans to speak at and view or listen to proceedings remotely via their computer or phone. Thoughtful consideration should be given to holding evening and/or week-end comment sessions, offering Spanish and American Sign Language (ASL) interpreters, and incorporating accommodations, such as access to public transportation, that can increase engagement.

3. Provide an estimated time on the agenda for hearing an item that is expected to have public comment. Members of the public are often taking time away from work or family to speak before government officials. Policymakers should use their discretion to adjust the agenda as needed during the meeting to ensure an item that meets this criterion remains at the time listed or within a two hour time frame following the time it is listed on the agenda.

4. Instruct staff to enhance and maintain a one-stop user-friendly website in English and Spanish that includes features such as a fully functional search bar, tools to reduce monthly electric bills, a method to pose questions and provide comments, and a calendar of upcoming meetings and events.

5. Require staff to conduct education and outreach such as social media, text and email messages, mailings, and community events with a consumer-oriented and energy-saving focus. Education and outreach should be mindful of demographics and continue to evolve.

6. Promote consumer tips such as the Arizona PIRG Education Fund's Resource Guides: Ways to Save Energy at Home and Reducing Your Energy Bill. Direct individuals needing financial assistance to help with utility bill payments to their local utility or the non-profit Wildfire which provides resources in every county in Arizona.

7. Consistently invite, encourage, and welcome diverse stakeholder and consumer involvement in proceedings.

8. Be accessible and accountable, which instills confidence in the decision-making process.

9. Conduct regular written and verbal reports to keep the public aware of progress made, efficiencies enacted, barriers faced, and challenges overcome.

10. Evaluate key policies proposed and adopted based on credible data. Publicly provide an evaluation based on data as well as lessons learned, best practices, and next steps.

Prepared By: Diane E. Brown, Executive Director, Arizona PIRG Education Fund: dbrown@arizonapirg.org or (602)318-2779 (c).

October 10, 2017

Arizona Corporation Commission
1200 W. Washington St.
Phoenix, AZ 85007

RE: Docket Numbers: E-01345A-16-0036 & E-01345A-16-0123

Dear Chairman Forese and Commissioners,

On behalf of the organizations signed below, please find feedback on the Arizona Public Service Company (APS) final Customer Education and Outreach Plan ("Final Plan").

As you are aware, APS filed a draft Customer Education and Outreach Plan ("Draft Plan") on September 11, 2017. Our organizations filed comments in response to that Draft Plan. Those comments outlined a number of gaps and concerns we identified with APS' proposal.

While we appreciate that APS met recently with advocates and incorporated a few of our suggestions in its Final Plan, major gaps and concerns remain. As elected officials, Arizonans count on you to ensure ratepayer money is used prudently. Without knowledge of how APS plans to quantify, measure, or report on the effectiveness of the Customer Education and Outreach Plan or a clear understanding of the budget and expenditures, Commissioners, Commission Staff, and ratepayers will be left in the dark.

Our comments below describe how APS did or did not address our concerns in its Final Plan. We encourage you to require APS to provide more details to the Commission and stakeholders as outlined below.

Messaging, content and tactics

Stakeholder Comment: APS should provide the Commission with a comprehensive set of examples of the communications that various customer classes and groups will receive and how and when they will receive that information.

- **APS response to Stakeholder comment:**
  The APS Final Plan includes a high-level timeline that describes a three-phased approach to consumer outreach. For each of these phases, APS has provided high-level details about the tactics it will employ. APS also said it, "Intends to meet at least twice with stakeholders during the Transition process. These Stakeholder meetings will provide updates on Transition activities and early access to educational and marketing materials with supporting information."

- **Stakeholder response:**
  We appreciate that APS has committed to meet with stakeholders at least twice during this process. We encourage APS to meet with stakeholders before expending a significant amount of time or money on its messaging or materials. Consumer entities that work

directly with APS ratepayers on an ongoing basis can provide valuable input for APS to consider.

We are particularly concerned that the APS messaging is not resonating with its ratepayers. Stakeholders, including our organizations, have heard from a number of APS ratepayers who are confused about their recent bills. While we appreciate APS reviewing specific instances that we have brought to its attention, we are concerned that what we are hearing represents just "the tip of the iceberg." Recent communication with low-income customers who are being disconnected in large numbers, without meaningful interaction by APS, leaves us skeptical of the effectiveness of the company's messaging and transition plan.

Stakeholder Comment: APS should provide communications in Spanish or other languages.

- **APS response to Stakeholder comment:**
  APS will provide, "Spanish language messaging to customers"… for "Spanish-speaking customers who have requested to receive communications in this manner."

- **Stakeholder response:**
  The Stakeholders appreciate APS' confirmation that it will provide Spanish communications.

Stakeholder Comment: APS should clarify if customers will be charged for text messages, and how customers can opt-out of communications if they wish not to be charged.

- **APS response to Stakeholder comment:**
  Customers are not and will not be charged by APS for text messages. However customers could be charged by their cell phone carrier depending on their data package and text messaging plan. Customers who choose to enroll in text messaging will have the option to opt-out any time via aps.com.

- **Stakeholder response:**
  Text messages could become an unwelcome expense for customers who enroll in text notifications and do not have an unlimited text messaging plan or a sufficient data package. APS' landing page about residential text message enrollment and other marketing and enrollment materials should include notice that, "Message and data rates may apply." While APS' indicates that customers can opt-out at any time via its website, this may not be the best option for all customers, and no information about the opt-out process is provided on the aforementioned landing page. It is also unclear if customers have other options for opting-out, for instance, via text message to APS. For these reasons, we recommend that APS works with stakeholders to review the text messaging enrollment process and identify areas where the presentation and availability of information could be improved.

<u>Stakeholder Comment</u>: APS should explain how it will incorporate messaging on the availability of energy efficiency programs, services, and tools to help customers manage their rate options.

- **APS response to Stakeholder comment:**
  In its Final Plan, APS said it will incorporate "Demand Side Management messaging." APS has also included a goal in its Final Plan to, "Familiarize customers with opportunities to save... [through] available Demand Side Management programs."

- **Stakeholder response:**
  The Stakeholders appreciate APS' confirmation that it will provide demand side management messaging to customers and that it has a goal to familiarize customers with its programs. However, we are concerned that APS has not provided more detail about its plans. Our concerns are heightened by that fact that APS has proposed to cut and weaken energy efficiency programs significantly in its 2018 Demand Side Management (DSM) Plan filed with the Commission in September. APS' energy efficiency offerings are essential to help residents control their energy costs and reduce the effect of the rate increase, and the Commission should ensure that APS remains committed to these important programs when it reviews and approves APS' 2018 DSM Plan filing.

  We also encourage APS to meet with stakeholders before expending a significant amount of time or money on its demand side management messaging or materials. Consumer entities that work directly with APS ratepayers on an ongoing basis can provide valuable input for APS to consider.

<u>Enrollment and transition process to new rates</u>

<u>Stakeholder Comment</u>: APS should provide the Commission with monthly reports that provide information on the number of customers by customer class projected to and enrolled and transitioned to each rate plan. APS should provide the Commission with information on customers who are put on the default rate plan and the plan that these customers choose after the 90-day period expires. Information should be provided on the number of customers who prefer to use a plan other than the demand rate or time-of-use (TOU) rate options.

- **APS response to Stakeholder comment:**
  APS did not respond to this comment.

- **Stakeholder response:**
  The Stakeholders continue to stand by our recommendation. APS has access to data sets that they utilize to evaluate the effectiveness of their efforts. On a monthly basis, Commissioners, Commission Staff, and stakeholders should have access to their analysis of the mandatory default rate and other rate plans to evaluate successes and shortcomings and to propose changes in real time.

Budget and expenditures

Stakeholder Comment: The APS plan does not describe a budget or how funds will be spent. A budget should be provided so that the Commission and stakeholders understand how ratepayer money will be invested. APS should report regularly on actual expenditures relative to its budget.

- **APS response to Stakeholder comment:**
  APS, "Included the $5 million of collected but unallocated Demand Side Management funds approved in the [rate case] Decision for rate education in its 2018 DSM Implementation filing and will provide an update through the normal course of the Annual Performance Report compliance filing."

- **Stakeholder response:**
  The stakeholders find this response inadequate. Commissioners, Commission Staff, and stakeholders should understand how ratepayer money is being spent. APS has not clarified the total budget or how the budget will be allocated amongst tactics and activities. Based on the APS response and the limited information available in the APS 2018 Demand Side Management (DSM) Plan, it appears that APS could be spending $6.5 million on the Final Plan, not $5 million. This investment is considerable, and there should be transparency around the total budget amount, how that budget will be spent, and expenditures relative to the total budget.

  The APS plan to report on its expenditures is also unclear. Will APS report on its Final Plan expenditures via the DSM reporting process or just the $1.5 million proposed for "Energy and Demand Education" in its 2018 DSM Plan?

  APS should be required to provide a budget and report quarterly on its expenditures in the rate case docket so that interested parties have ready access to the information.

Quantifying, measuring, and reporting on effectiveness

Stakeholder Comment: APS should propose and the Commission should establish and approve metrics for quantifying and measuring the effectiveness of APS' outreach and education activities. APS should also describe the tracking and reporting mechanisms it will implement to report on these metrics.

- **APS response to Stakeholder comment:**
  The Final Plan describes APS' five goals for its Final Plan but provides no meaningful information on what "success" means relative to these goals; the mechanisms and metrics that will be employed to evaluate "success" relative to these goals; or the process by which APS will report back to the Commission and stakeholders on the effectiveness and "success" of its Plan.

- **Stakeholder response:** The Stakeholders continue to stand by our recommendation.
  In order for Commissioners, Commission Staff and stakeholders to measure success, APS needs to provide specific goals and actual results. While we understand that some trial

and error is likely to exist, understanding the assumptions and having the ability to provide input early on can likely benefit APS and its ratepayers.

Below are the suggested metrics we previously recommended. We urge the Commission to require APS include such metrics in its Final Plan:

a. Open rates and click-thru rates for rate education-related emails.
b. Percent increase in frequency of visits to customers' online accounts.
c. Number of rate-related customer complaints.
d. Number of views to rate education web pages.
e. Number of customers who have changed rates over the last quarter.
f. Number of events and presentations held in support of rate education and outreach and the number of people reached.
g. Number of community partners utilized to support rate education and outreach and the number of people reached.
h. Customer awareness of rate plans that may help them to mitigate electricity expenditures.
i. Customer knowledge of where to go to get more information about how to manage their energy use.
j. Customer understanding of how energy use can impact electricity bills.
k. Customer awareness of the rebates, energy efficiency programs, and tips offered by APS that can help them manage their energy bill.
l. Length of time, number of pages visited, unique visitors to the APS website.
m. Number of featured stories in the news regarding APS' rate reform.

Stakeholder Comment: The Commission should ensure that it receives a written report from APS no later than June 30, 2018. This report should describe how well the plan was executed and any lessons learned.

- **APS response to Stakeholder comment:**
  APS did not respond to this comment.

- **Stakeholder response:**
  The Stakeholders continue to stand by our recommendation. Commissioners, Commission Staff and APS ratepayers should have the ability to understand and evaluate how efficiently and effectively APS implemented its Customer Education and Outreach Program. Lessons learned during this process will be instructive for other plans that come before the Commission.

Regular engagement with consumer groups

Stakeholder Comment: APS should formalize a consumer stakeholder working group that meets regularly to provide input and recommendations on the Plan's development and implementation.

- **APS response to Stakeholder comment:**
  APS, "Intends to meet at least twice with stakeholders during the Transition process. These Stakeholder meetings will provide updates on Transition activities and early access to educational and marketing materials with supporting information."

- **Stakeholder response:**
  The Stakeholders appreciate that APS is willing to meet at least twice with stakeholders. These types of meeting are invaluable because participating stakeholders can provide perspectives about the unique constituencies that they understand and represent. We recommend that APS file meeting notices in the APS rate case docket so that all interested stakeholders have fair and equal notice and opportunity to participate in these important stakeholder meetings.

We understand that implementation of the APS Customer Education and Outreach Plan is moving forward. Please require APS to provide more details, such as those outlined above, to the Commission and stakeholders by October 18, 2017.

Sincerely,

Cynthia Zwick
Arizona Community Action Association

Doug Bland
Arizona Interfaith Power & Light

Diane E. Brown
Arizona PIRG Education Fund

Dru Bacon
Conservative Alliance for Solar Energy

Bret Fanshaw
Environment Arizona Research & Policy Center

Sandy Bahr
Sierra Club – Grand Canyon Chapter

Ellen Zuckerman
Southwest Energy Efficiency Project

Arizona PIRG Education Fund
130 N. Central Ave., Ste. 202 | Phoenix, AZ 85004
www.arizonapirgedfund.org (602) 252-9227 (ph)

Arizona Corporation Commission
1200 W. Washington St.
Phoenix, AZ 85007

December 9, 2019

Dear Chairman Burns and members of the Arizona Corporation Commission,

RE: Docket Number E-01345A-19-0003

On behalf of the Arizona PIRG Education Fund, I write to respond in part to the letter by Commissioner Dunn filed in the docket on November 20, 2019. In particular, I am replying to Commissioner Dunn's request for input from participating stakeholder groups on the effectiveness of APS' engagement efforts.

Below please find key highlights of the Arizona PIRG Education Fund's involvement in and stemming from the previously adopted APS rate case; and proposed next steps for the Commission and APS.

Background

As you likely know, the Arizona PIRG Education Fund opposed the APS rate case approved by the Commission on August 15, 2017. We agreed with the initial assessment of both Commission Staff and RUCO that a rate increase was not warranted, and during public proceedings also cited additional policy concerns.

Throughout the rate case, Arizona PIRG Education Fund staff and volunteers traveled across APS territory. We provided background on the rate case through individual conversations with residential ratepayers, organizational leaders and small business owners. We listened to impacts the proposed rate and fee increases could have on utility bills and presented opportunities to be involved.

As a result of our work, newly-involved APS ratepayers turned out for public hearings held in Flagstaff, Clarkdale, Phoenix and Yuma; small businesses, consumer organizations and hundreds and hundreds of APS ratepayers from over 60 municipalities urged the Commission to reject the APS rate case; and we helped generate media attention in more than two dozen different outlets across APS territory, including television, radio and print.

Although the Commission vote did not side with these ratepayers, the Arizona PIRG Education Fund stated that as APS conducts its Customer Education and Outreach Plan, we would work with the utility and other interested parties to help customers understand changes to their bills and options to reduce their energy consumption and save money.

APS' Customer Education and Outreach Plan

Soon after APS began communicating the new rate plans with its customers, we began directly hearing complaints from ratepayers and indirectly hearing complaints through other organizational leaders, most notably Conservative Alliance for Solar Energy and Arizona Community Action Association (now known as Wildfire: Igniting Community Action to End Poverty in Arizona).

Upon reviewing APS' draft Customer Education and Outreach Plan, our organizations and others entered a joint letter into the docket stating that we found the Plan to be "unclear" and that "specific details are needed before the Commission can properly evaluate whether or not to approve the proposal." The letter included specific recommended improvements related to messaging, content and tactics; enrollment and transition process to new rates; budget and expenditures; quantifying, measuring, and reporting on effectiveness; and regular engagement with consumer groups.

Representatives of CASE, Wildfire, and the Arizona PIRG Education Fund met with representatives of APS to discuss our concerns and seek improvements prior to the filing of their final Plan.

While we recognized and described how APS incorporated a few of our suggestions in its final Plan, we noted in a joint follow-up letter to the Commission that major gaps and concerns remained. Our letter stated, "Without knowledge of how APS plans to quantify, measure, or report on the effectiveness of the Customer Education and Outreach Plan or a clear understanding of the budget and expenditures, Commissioners, Commission Staff, and ratepayers will be left in the dark."

When efforts to improve communication and the Plan were not as successful as we thought necessary, Arizona PIRG Education Fund and Wildfire called on Commissioners to act, through an op-ed published in the *Arizona Republic*.

Meetings with RUCO, Commission Staff, APS and Representatives of Consumer Entities

A combination of the above can reasonably be attributed to the establishment of RUCO-led meetings to understand issues and implement solutions for APS ratepayers. The meetings, which at moments were quite tense, largely sought to identify and address systemic issues.

The Arizona PIRG Education Fund shared information based on conversations with APS customers, which included confusion related to E-3, estimated billing, payment plans, meter problems, solar plans, new plans and Time-of-Use hours. We reviewed APS customer complaints filed with the Commission and through online sources and provided meeting participants with a sample (over 100) of the comments that had recently been made public and encouraged follow-up, including an investigation into the claims. We noted that, at a minimum, the need existed for APS to immediately improve communication with its customers, and that we remained willing to assist.

As progress was slowly occurring, Ms. Champion filed a Citizens Complaint calling for a re-hearing of the APS rate case, which in our opinion shifted the focus of APS, and these group meetings ceased.

Policies to Benefit APS Ratepayers

Even though we opposed the rate case, we didn't see a viable path to a favorable outcome in the re-hearing effort. However, we weighed in as discussion was occurring about the next phase of the APS rate case. In our letter to the docket related to the Four Corners Power Plant, we stated "Based on earnings significantly greater than projected; election related spending; advertisements that only promote APS and not programs that directly benefit customers; contributions to teachers for classroom supplies; donations to community groups without a link to bill assistance; and sponsorship of non-energy related conferences, a case can be made that an additional ratepayer increase may not be justified." We went on to say that "Without data provided from the most recent APS rate case, it is also hard to assess the costs and benefits to ratepayers." And we encouraged the Commission to require APS to provide more details, such as those outlined in our letter.

During the Open Meeting in June 2019, the Arizona PIRG Education Fund supported policies that were before and subsequently adopted by the Commission including: formation of a stakeholder group to suggest more effective ways to educate customers on rate plans and ways to cut back on energy usage; proforma billing; and tracking and quarterly reporting by APS on its Customer Education and Outreach Plan. We also appreciated Commission efforts to have APS provide updated earnings data and variances between assumptions in its billing determinants.

And while incorporating ratepayer education and outreach was and is an integral component of our work, we also successfully pursued other policies to benefit APS ratepayers and consumers in our state ranging from the Code of Ethics to the Electric Vehicle Policy and EV Policy Implementation Plan. Further, we became and remain actively engaged in efforts ranging from a stronger Termination of Service Policy to extending and expanding Arizona's Energy Efficiency Standard.

Assessment of Stakeholder Engagement and Recommended Next Steps

Following approval of the rate case, meetings to discuss customer education and outreach with APS, Commission Staff, RUCO and consumer entities did not yield our desired results for ratepayers. However, in recent months we have begun to see a positive shift in our discussions. Most notably, ourselves and other advocates are starting to receive more detailed information and opportunities to offer input; and we are seeing suggestions from advocates incorporated into educational materials and proposed policies. In particular, the Arizona PIRG Education Fund considers the RUCO-led discussions on utility disconnections and the APS-led DSM Collaborative as steps on the right path. However, in order to better benefit ratepayers, APS needs to take bigger and swifter steps.

After a series of serious debacles, APS needs to revert to common-sense basics by putting ratepayers before shareholders and being proactive vs. reactive.

The Arizona PIRG Education Fund recommends the Commission direct the following to occur:

1. Monthly meetings between APS, Commission Staff, and RUCO and representatives of consumer organizations to the extent the latter are willing to participate. The Arizona PIRG Education Fund has previously stated that we see the purpose of consumer work group meetings as an opportunity to determine how to best achieve a common goal of equipping ratepayers with the information, tools, and resources they need to make knowledgeable decisions about their best rate plans. In the meetings, advocates should share what we are hearing in the field and APS should provide responses and seek input *before* rolling out new materials and tools. We encourage Mr. Guldner to attend the consumer work group meetings on at least a quarterly basis.

   As you recall, the Commission directed APS to "fund and implement a Customer Outreach and Education Program to be developed and administered by Commission Staff." However, despite repeated requests Commission Staff has failed to act. As Commissioners, we count on you to follow-up with Staff. Directing Staff and APS to participate in these meetings is essential to help address emerging and ongoing issues.

   The rate comparison tool is the latest example of how a significant error may have been averted prior to its launch and/or update. The consumer work group could have tested and improved the tool from various vantage points, similar to efforts the Arizona PIRG Education Fund led with entities prior to the launch of openbooks.az.gov, Arizona's Financial Transparency Portal. If a problem arose, we could understand and help communicate the issue(s) to consumers.

   Furthermore, using this example, we could have a consistent opportunity to pose questions and gain answers ratepayers are seeking such as: what happened and how does APS know this is the extent of the problem and not more than 12,000 ratepayers were negatively impacted; what rate plan(s) were most ratepayers told was most economical for their household; what information are customer service representatives currently using to help ratepayers find their most economical plan and what is the level of confidence that information is accurate; what level of additional training are customer service representatives receiving to better assist ratepayers; who is paying for the replacement tool (ratepayers should not bear the cost for APS' mistake); and how is APS' ensuring a problem like this does not occur again.

   And we could urge action to benefit ratepayers, such as our request for APS to automatically refund customers impacted by the flawed rate comparison tool vs. customers needing to request a refund (we are pleased that APS has now committed to automatically providing a credit).

   To us, it is noteworthy that despite offers to provide input on proforma billing, to the best of our knowledge, no consumer entity has been asked for suggestions by APS or Staff.

The Arizona PIRG Education Fund recently let APS know basic components we think are important for the customer including simplicity, monthly and annual saving comparisons with an easy-to-understand description of TOU and demand rates, along with visuals and text that stands out. Conversations through a consumer work group *before* design occurs can save time, effort and money.

2. Monthly reports to the docket from APS on key items, including take-aways from the Consumer Work Group. One of the frustrations that the Arizona PIRG Education Fund and others share is not having robust data from APS to make informed assessments on how widespread a problem or how meaningful a proposed solution. APS has started to provide more information upon requests from Commissioners and stakeholders - such as utility disconnection reports - however, the information needs to be more comprehensive (in this instance, more in line with what TEP and UNS have provided), and more frequently include metrics, a thorough analysis, and budgetary information. APS should also docket final materials distributed to ratepayers and significant updates placed on their website.

The Arizona PIRG Education Fund recommends the Commission request the following of APS:

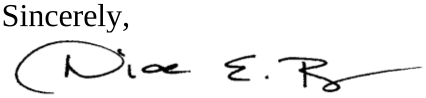
1. Encourage Mr. Guldner to meaningfully interact with "everyday" ratepayers annually. Mr. Brandt's appearance before the Commission on September 4, 2019 demonstrated that he was out of touch with APS customers. Mr. Guldner's participation in at least a couple of APS' community events and/or focus groups with randomly selected ratepayers can provide a more realistic sense of their questions and issues and shift the focus back to ratepayers before shareholders.

2. File changes to their recently proposed rate case. While we understand it is premature to *require* APS to amend or refile their proposed rate case, as Commissioners you can send the signal that ratepayers should not be on the hook for costly educational materials and tools that failed nor should APS have a return on equity that surpasses 10%, in fact it should be under 10%.

The Arizona PIRG Education Fund appreciates opportunities to participate in Commission proceedings and the conversations we have had with each of you. While fundamentally we believe APS rates and fees should be lower, utilities should not spend in political campaigns and funding for energy efficiency programs should be increased, the request we are responding to and the recommendations we have provided should serve as low-hanging fruit to begin restoring confidence in APS and the Commission.

Please feel free to contact me directly at (602)318-2779 (c) or dbrown@arizonapirg.org if you have any questions or wish to discuss.

Sincerely,



Diane E. Brown
Executive Director

Arizona PIRG Education Fund
130 N. Central Ave., Ste. 202 | Phoenix, AZ 85004
www.arizonapirgedfund.org (602) 252-9227 (ph)

Arizona Corporation Commission
1200 W. Washington St.
Phoenix, AZ 85007

June 17, 2020

Dear Chairman Burns and Commissioners,

RE: Docket Numbers E-01345A-19-0003 & E-01345A-19-0236

On behalf of the Arizona PIRG Education Fund, I am writing to express appreciation for the thorough report written by Ms. Alexander, the Commission's Consultant, regarding Arizona Public Service's Customer Education & Outreach Plan (CEOP) and implementation. In addition, I want to note modest progress made since APS' "final" CEOP was filed; and offer the Commission recommended next steps.

Background

First and foremost, the report from the Commission's Consultant should not be taken lightly. I had the opportunity to speak with Ms. Alexander prior to the evaluation she filed, and it was extremely clear through the thoughtful questions posed that she was doing her homework.

While many of the findings in the Commission's Consultant report are not new[1], the details presented offer an important synopsis of what occurred and opportunities to ensure the same inadequacies are not repeated moving forward. Instead of rehashing all the critical and ongoing concerns raised in the evaluation, I want to provide additional thoughts.

Certainly, APS failed to develop and implement their CEOP in a manner beneficial for its ratepayers. However, Commission Staff and Commissioners also bear responsibility for failing to ensure APS had and was executing a solid plan. Neither APS *nor* Commission Staff took input from advocates seriously. Despite attempts to meet with Staff prior to APS finalizing its CEOP, we were not provided an opportunity to meet until after the final CEOP was filed and deemed acceptable to Staff. The confluence of taking our concerns directly to Commissioners, Ms. Champion filing a Citizens Complaint which called for a rehearing of the APS rate case, and members of the media reporting on the confusion customers were experiencing with APS' new rate plans presumably contributed to the modest improvements realized since the rate case decision.

[1] In September & October 2017, advocacy organizations including Arizona PIRG Education Fund docketed letters noting deficits in the APS CEOP filing: http://docket.images.azcc.gov/0000182833.pdf & http://docket.images.azcc.gov/0000183169.pdf. In December 2019, Arizona PIRG Education Fund filed a reply to Commissioner Dunn's request for input from participating stakeholder groups on the effectiveness of APS' engagement efforts: https://docket.images.azcc.gov/E000004025.pdf.

Progress Due to Action by Commissioners
Prior to providing recommended next steps, it is important to acknowledge that policy advancements related to problems stemming from the rate case and a deficient CEOP were due in large part to Commission action vs. that of APS.

The Commission Consultant's report recognizes that APS is implementing pro forma billing and has instituted the Consumer Work Group (monthly engagement with advocates), both which were a result of Commissioners' direct involvement. In our opinion, the good news is that APS is complying and providing the Commission with relevant and frequent updates, APS staff is responsive to questions and critique, and recent meetings – such as on their proposed Demand-Side Management Plan – are giving stakeholders an opportunity to weigh in before proposals come to the Commission. Additionally, Mr. Guldner publicly committed to participate in quarterly meetings of the Consumer Work Group, APS created a Customer Advisory Board, Secret Shopper program and Mobile Services Team. The bad news is that basic practices took Commissioner engagement and the need for your continued oversight and specific directives remain.

Recommended Next Steps

1. **Direct Commission Staff to participate in the Consumer Work Group.** APS typically provides the Consumer Work Group with data and analysis, and discussion is often robust and informative. APS and advocates could benefit from Commission input and vice versa.

2. **Require APS to provide the Commission with a *comprehensive* Customer Education and Outreach Plan by September 30, 2020, with the item placed on an Open Meeting agenda for discussion this Fall.** The Arizona PIRG Education Fund respectfully requests you require APS to incorporate the Commission Consultant's recommendations for this Plan along with recommendations from advocates cited in this document. Further, the Plan needs to be written with ratepayers, not shareholders, in mind.

   Since APS controls placing advertisements, social media posts and communication through customer bills, efforts should closely track the metrics for not only how customers are being reached but how they are responding and the associated costs for each method.

   While APS is making strides, more sensitivity still needs to be incorporated in the utility's education and outreach efforts. For example, not every household can realistically "Shift, Stagger and Save", there are homes without internet service, and one-size messaging and messengers does not fit all for a utility with such a large and diverse service territory.

   In addition to the quarterly CEOP reports, there should be an annual report that provides a thorough evaluation of the Plan and any proposed adjustments for the upcoming year. APS Management should present the annual report findings at an Open Meeting before the Commission, with the opportunity for the public to provide comment.

   (The Arizona PIRG Education Fund encourages the Commission to require major companies under your purview, including Johnson Utilities and CenturyLink, to provide similar plans and reports).

3. **Require APS to establish a 24-7 call center for general customer support.** Soon after the rate case was adopted and customers experienced exceptionally long hold times, we began advocating for a 24-7 call center. As noted in the Commission Consultant's report, APS' customer service performance at its call center remains below average. While this measure will not solve the major issues, it is likely to help a number of customers. In our experience, customer service improvements have been made but inaccurate information continues to be given to customers bringing into question training and retraining protocols.

4. **Signal to APS the need to revisit their pending rate case.** As previously stated, we understand it is premature to *require* APS to amend or refile their proposed rate case. However, as Commissioners you can send the signal that APS should not have a return on equity that surpasses 10%, in fact it should be under 10%. The Commission Consultant's report and concerns posed by us and other advocates raise additional considerations that should be addressed such as the complexity of the rate plans, demand charges, and mandatory rate plans.

5. **Raise questions and publicly provide your perspective to let APS ratepayers and other Arizonans know you are paying attention and when warranted – such as now, act.** The Commission Consultant's report, coupled with well-founded concerns brought to light, should be a harsh lesson in the need for Commission Staff and Commissioners to exercise stronger oversight. Ultimately education and outreach alone will not help struggling ratepayers, changes are needed to stop unjust and unreasonable utility rates and fees.

As always, please feel free to contact me at (602)318-2779 (c) or dbrown@arizonapirg.org if you have any questions or wish to discuss.

Sincerely,

Diane E. Brown

Diane E. Brown
Executive Director

ORIGINAL OPEN MEETING AGENDA ITEM

Arizona Corporation Commission
DOCKETED
JUN 20 2019
DOCKETED BY

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AZ CORP COMMISSION
DOCKET CONTROL
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Arizona Corporation Commission
1200 W. Washington St.
Phoenix, AZ 85007

June 19, 2019

Dear Chairman Burns and Commissioners,

RE: Docket No. E-00000A-19-0128 and Docket No. RU-00000A-19-0132

On behalf of Wildfire, Arizona PIRG Education Fund, St. Vincent de Paul, and the Residential Utility Consumer Office (RUCO), we write to offer our joint recommendations on electric utility disconnections.

The death of Ms. Pullman is a tragedy – one that must ***never*** happen again. While this devastating and deeply troubling incident occurred in APS's service territory, we are also very concerned that similar situations may have occurred or could occur in the service territories of other electric, water, and gas utilities that you regulate.

We appreciate the questions that Commissioners have raised to learn how and why this incident occurred and to explore and implement safeguards to ensure that utility disconnections don't result in additional deaths, illness, or harm. We also appreciate the work of Commission Staff to propose revisions to the Termination of Service rule for electric utilities, in an expedited fashion.

However, **we have concerns about the unintended consequences that may arise should the Commission hastily adopt the proposed changes.** During any moratorium period, it's likely some customers would accrue a significant amount of unpaid bills and fees — a financial burden that would become unmanageable by the time the moratorium ends. Additionally, when customers accrue high amounts of unpaid bills, the support available from community and charitable organizations to assist with bills is often insufficient to prevent disconnection. Both consequences would cause additional customer disconnections, harm, and hardship, and be counterproductive to the overall intention of the Commission's rulemaking.

Given the very real potential consequences, **we respectfully request that the signatories of this letter, working with Commission Staff, be given an opportunity to discuss and amend the proposed rules to ensure that potential negative ramifications are not in any way exacerbated.** Each of our entities recently were invited to participate in utility led discussions about disconnections. Based on insight gained in these meetings and our experience working with consumers, we believe we have unique perspectives to offer.

We also urge the Commission to engage in a comprehensive review of utility disconnection practices in addition to and separate from any revisions made to the Termination of Service rule – an approach informed by data; oriented first toward solutions that mitigate the health and human impacts of disconnection; and that directs the development and implementation of a suite of concrete/proactive actions, policies, programs, procedures, and solutions focused on the goal of eliminating all utility disconnections.

Below please find a suggested timeframe, framework and stakeholder working group process developed and proposed this week to Arizona Public Service Company and shared with Tucson Electric Power and Salt River Project. This document outlines the urgent steps and actions we believe must be taken within 90 days of the Rule's adoption to inform, develop, and implement a comprehensive approach and response to utility disconnection. We have slightly modified this framework for a potential Commission-led process and respectfully request that you review and consider this proposal and direct a stakeholder working group process for immediate implementation.

In order to ensure that no customer harm is unintentionally done, we respectfully recommend that the Commission:

1. Put a moratorium on regulated electric utility disconnection in place until Friday, July 19th, 2019 or until comprehensive emergency rules are adopted by the Commission.

2. Allow the entities mentioned above the ability to meet with Commission Staff and propose comprehensive Termination of Service Rules for consideration by the Commission.

3. Immediately employ the framework and stakeholder working group process outlined below in order to compile and consider all of the necessary information it needs to develop and adopt a comprehensive approach on utility disconnection, including on the processes and procedures surrounding the current and any future proposed moratoriums.

4. Adopt a comprehensive approach on utility disconnection as soon as possible.

Regardless of the Commission's actions and decisions at its Staff Meeting on Thursday, June 20th, 2019, we recommend that the Commission direct the immediate implementation of the proposed stakeholder working group process outlined above.

Please feel free to contact any or all of us with questions or suggestions.

Sincerely,
Cynthia Zwick, Executive Director, Wildfire, (602) 604-0640, czwick@wildfireaz.org
Diane E. Brown, Executive Director, Arizona PIRG Education Fund, (602) 252-9227, dbrown@arizonapirg.org
Cherylyn Strong, Director, Resource Center, St. Vincent de Paul – Cstrong@svdpaz.org
Jordy Fuentes, Director, RUCO – jfuentes@azruco.gov

Proposed Commission-Led Stakeholder Process on Utility Disconnections

Work Group Goals

To conduct an urgent, comprehensive review of the disconnection policies and procedures of the electric utilities regulated by the Arizona Corporation Commission; their impacts; and affected populations to identify concrete actions, policies, programs, and procedures that each regulated utility should implement to protect the well-being of Arizona ratepayers. The Disconnection Work Group will be guided by the overarching goal to eventually eliminate all utility disconnections.[1]

Work Group Principles

The work group will be:

1. **Oriented First Toward Solutions that Mitigate the Health & Human Impacts of Disconnection**

2. **Structured & Process-oriented**
    - Work will be guided by ground rules, goals, a work plan, and an associated timeline.
    - The overall work will be completed within 90 days.
    - Materials and an agenda will be provided at least 48-hours before each meeting.
    - Within 48 hours after each meeting, Commission Staff will synthesize the discussions and decisions from each meeting for Work Group participants.

3. **Transparent & Communicative**
    - Commission Staff will provide regular (bi-weekly) status updates to the Commission on the Work Group's activities.
    - Commission Staff will provide regular (bi-weekly) status updates that are available publicly via eDocket.
    - All final recommendations and implementation actions will be synthesized and filed with the Commission including for Commission review and approval if/where necessary.
    - All final recommendations and implementation actions will be synthesized and made publicly available. Status updates on the implementation of these recommendations and implementation actions will be made available publicly on a regular basis (monthly).

4. **Inclusive & Collaborative**
    - At a minimum the Work Group shall include representatives of organizations that advocate on behalf of: low-income consumers; consumers; senior citizens/elderly; the medically vulnerable; energy efficiency; Latino/Hispanic communities; other non-English speaking communities; and other vulnerable communities; and shall also include representatives from the faith community; the Residential Utility Consumer Office (RUCO); and representatives from each of the regulated electric utilities.
    - Commission Staff and Work Group members will proactively identify and invite additional potential participants with a lens toward participants that can provide perspectives on equity and public health and that serve, work with, or understand the communities and customers most vulnerable to disconnection.

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[1] The scope of this work includes disconnections at all times of the year including during the summer and winter.

- Participating stakeholders must abide by the Work Group's ground rules.

5. **Data-driven and -Supported**

6. **Fast Acting & Timely**

7. **Comprehensive & Proactive in its Approach**
   - In addition to looking at the regulated electric utility disconnection policies and procedures, the Work Group will conduct a comprehensive deep dive to understand disconnection risk factors and to identify other concrete/proactive actions, policies, programs, and procedures that each utility should implement in order to achieve the overarching goal to eventually eliminate all utility disconnections.

Work Plan

At a *minimum* the Work Group will:

- Conduct a deep-dive analysis of disconnection data for the last five years; a demographic analysis; a housing and locational analysis; a market segmentation analysis[2]; focus groups; and surveys to at a minimum elucidate disconnection trends and understand who is being disconnected, influences on disconnection, and the impacts of disconnection
- Establish risk factors and an associated framework to proactively identify customers vulnerable to disconnection and to recommend and implement a suite of concrete/proactive actions, policies, programs, and procedures to help ensure that at-risk customers never disconnect including recommendations for bill assistance, energy efficiency programs, energy education, etc. and for the selection of and enrollment in rate options
- Benchmark the disconnection policies of regulated electric utilities in Arizona against other utility policies nationally
- Review and recommend protections against disconnection
- Review and recommend limitations on disconnection
- Review and recommend disconnection communications and communication procedures, including resources provided to consumers upon disconnection
- Review and recommend communications, communication procedures, and protections for customers who lose power/are disconnected for reasons other than unpaid electricity bills
- Review and recommend improvements to payment assistance options
- Review and recommend improvements to rate options including for the selection of and enrollment in those rate options
- Review and recommend improvements to energy efficiency programs and services targeted toward vulnerable and at-risk populations
- Review and recommend improvements to education efforts, including energy education efforts
- Review and provide recommendations on reconnection processes including reconnection fees and deposits
- Review and provide recommendations on programs, services, and communications for customers before and after they have been reconnected
- Establish goals, metrics and reporting around disconnection/termination of service processes

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[2] A market segmentation analysis would partition APS customers into groups of customers with similar needs and/or characteristics.

- Review communications and procedures related to the current and any proposed disconnection suspension/moratorium period

Arizona PIRG Education Fund

wildfire
Igniting Community Action to End Poverty in Arizona

September 15, 2020

Arizona Corporation Commission
1200 W. Washington St.
Phoenix, AZ 85007

RE: INVESTIGATION AND COMPREHENSIVE REVIEW OF THE COMMISSION'S DISCONNECTION RULES AND THE DISCONNECTION POLICIES OF PUBLIC SERVICE CORPORATIONS. (DOCKET NO. E-00000A-19-0128)

Dear Chairman Burns and Commissioners:

We are writing in regards to Commissioner Kennedy's thoughtful letter dated September 2, 2020. In her letter, she provides a number of proposals for how utilities may support their customers as we near the end of the emergency moratorium on electric and gas utility disconnections. Wildfire and our many partners and the Arizona PIRG Education Fund anticipate significant levels of debt that will have been accrued by customers unable to pay their bills during the COVID crisis, and a surge of requests for help paying those bills.

This pandemic has negatively affected our community in so many ways at an unanticipated depth and breadth in an environment that has not invested in our service delivery infrastructure. At the same time, there is an expectation that resources are adequate to provide the necessary support. Some individuals and families who lost jobs or had their hours significantly reduced received some relief through the Pandemic Unemployment Assistance program until that benefit expired. The disconnect moratorium has saved many families from losing utility services, which has been incredibly important particularly for families with medical issues or families with children now learning from home. While the moratorium is coming to an end, this health crisis shows no signs of ending, and the economic aftereffects will last for a long time as so many businesses, which we all supported in one way or another, have shuttered, closed temporarily, reduced employee hours or have indefinitely laid off employees.

The COVID CARES Act included approximately $16.4 million in Low Income Home Energy Assistance Program (LIHEAP) money for eligible members of our communities. Community Action Agencies (CAAs), which distribute those funds and serve households in every county in this state, continue to provide bill assistance support. We have, however, seen some patterns that may be important for you to know as we move deeper into this crisis.

ACC - Docket Control - Received 9/16/2020 10:40 AM
ACC - Docket Control - Docketed 9/16/2020 10:51 AM

When COVID hit, agencies had to completely revamp their service-delivery model as staff moved to remote work locations and families were afraid to leave their homes to seek assistance. Where the system once relied on in-person interviews in agency offices, staff now rely on phones, lobby kiosks, email, some online forms for applications and drop-boxes in office lobbies.

Many offices saw a decline in the number of customers seeking assistance with their bills. The shift in urgency, due in part to the relief provided by the moratorium, was replaced by an urgent need to receive help paying rent and making mortgage payments.

Customers who have never before been faced with an inability to pay their bills, and who have never before needed additional assistance, do now. And they have been faced with a benefits maze many find difficult to navigate.

It is also important to note that CAAs are required to run a 12-month program, meaning funding needs to be available throughout the year. Adjustments will be made to accommodate the anticipated surge, however, funding will be made available throughout the fiscal year, July through June.

Agencies and organizations receiving additional CARES Act funding to support their communities have taken an opportunity to bundle services when appropriate, matching eligible families with rent, mortgage and utility assistance. But the crisis and the need continue to grow while resources to help are not.

Each CAA has adapted service delivery for their community to serve as many families as efficiently as possible. Before the crisis, the State received LIHEAP funding to serve between 5-6% of eligible households. The number of eligible households has grown, along with the funding, by about $16 million, but the additional support will not cover the total need. Customers will likely still be frustrated by the process and their inability to receive the needed support.

All major gas and electric utilities in the state provide bill assistance. Wildfire administers those funds using the CAA network as well as staff of 21 additional community organizations. That funding is greatly appreciated, but, again, will not cover the growing need we're seeing. While each of these organizations and their staff work all day every day to serve as many customers as possible, there will still be a gap between the need and the resources available.

Wildfire and the Arizona PIRG Education Fund have been communicating via social media and other methods throughout the moratorium, encouraging customers to reach out to their utility company to either work out a payment plan now or ask to be put on a payment plan. We encourage customers to ask about and enroll in the utility discount program, and to make sure they are enrolled with the best rate for their household. And we also provide suggestions about how to save energy and money on bills.

We recommend that each of the major utilities provide a robust customer education and outreach plan no later than September 30, 2020 for Commissioner and stakeholder input. The filing should contain messages being conveyed -- including the items in Commissioner Kennedy's letter -- through TV, radio, social media and direct customer outreach to ensure customers, including those unaccustomed to seeking assistance and who likely are unaware of the options available to them, know their options and may then take advantage of them.

We respectfully request the Commission vote to ensure that every discount program in place today increase its eligibility threshold to 200% to ensure that customers receiving LIHEAP or other bill assistance are automatically enrolled in the appropriate utility discount program. Too many customers will not qualify for that discount today because the eligibility threshold of 150% of the federal poverty level for the discount programs is too low.

In Commissioner Kennedy's letter, a number of actions are proposed that, if taken, we believe will be of value to customers struggling to pay their bills.

While our organizations have been advocating for an automatic six-month payment period, with the opportunity to extend, because of the impacts of COVID-19, we support the proposed Deferred Payment Arrangement structure, including the 1/12 deduction for every payment made in compliance with the 24-month payment arrangement.

If a LIHEAP or bill assistance payment is applied to a customer's account while they are making payments on their established payment plan, the original payment plan should stay in place rather than being re-set, unless the re-set is to the customer's advantage. It is essential for payment arrangements to provide for affordable payments, otherwise a customer will be set up for failure and all ratepayers will be impacted. We believe extending the plans to 24 months will achieve a more affordable payment arrangement and provide an extra incentive for customers that are working hard to catch up on their bills.

In our meetings with representatives of the various utility companies during last summer's moratorium, there was concern that their experience demonstrated that longer payment plans were often broken before the completion of the term of the plan. There may be a number of reasons for this, including the fact that payments were too high to begin with or that those struggling to pay their bills on a monthly basis have every intention of paying, but with an added amount to pay, simply can't keep up. This may continue to be the case, however, the length of the payment plan and the incentive offered by the 1/12th payment incentive as you have proposed may mitigate this issue.

Furthermore, **we support the proposal for utilities to "not report late payments or nonpayment for active residential ratepayers to credit bureaus and reporting agencies during the moratorium, a two-month transition grace period, plus an extended four months (total six months after the end of the moratorium.**

Finally, we know that a number of utility staff have been working hard to answer data requests including an evaluation of last summer's utility disconnection moratorium and COVID-19 implications. **We think it is incumbent on the Commission to formally require the major utilities to provide monthly updates and a quarterly analysis related to this docket.** The Commission should also provide guidance to the utilities for the information it wants to receive. Any change(s) to data requests mid-stream are not likely to provide an accurate utility-utility or year-year comparison and may result in system changes that could result in additional costs to ratepayers.

Ultimately, the Commission needs to take a deeper look at rate design and systemic changes to better protect ratepayers. In the meantime, we thank you for the opportunity to offer our recommendations and efforts to protect those customers impacted by COVID while at the same time working to ensure that utilities receive payment for the many accounts that are falling behind.

Sincerely,

Cynthia Zwick, Executive Director
Wildfire
(602) 432-3464 (c)

Diane E. Brown, Executive Director
Arizona PIRG Education Fund
(602) 318-2779 (c)

Understanding Low-Income Arizonans & Preventing Utility Disconnections

Arizona PIRG Education Fund

SWEEP

wildfire
Igniting Community Action to End Poverty in Arizona

Arizona Corporation Commission
Termination of Service Workshop

January 30th, 2020

The Human Face of Utility Disconnection

Wildfire

14.9%

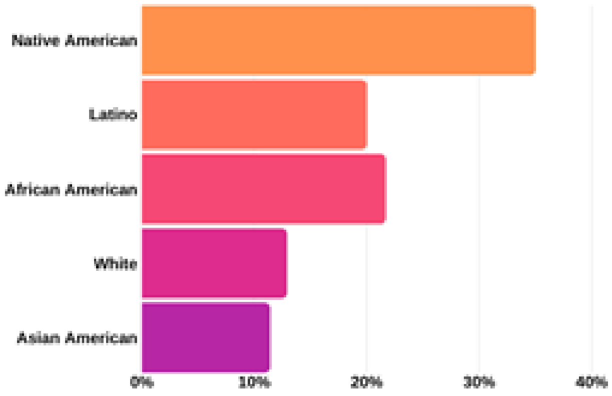
ARIZONANS LIVING IN POVERTY

20.4% Children

9% Seniors

33% Single Parents

VULNERABLE POPULATIONS



RACE & ETHNICITY

FAMILY OF FOUR

Poverty
$24,600/year
$2,050/month

Deep Poverty
$12,300/year
$1,025/month

Extreme Poverty
$2,516/year
$209/month

UNITED STATES SALARIES

TOP 1%: $1.15 million

BOTTOM 90%: $34,481

ARIZONA SALARIES

TOP 1%: $784,469

BOTTOM 25%: $23,640

The top 1% of earners in the US hold 40% of the nation's wealth

Did you know it will take...

84 & 228 years

For Latino and Black family wealth, respectively, to match 2016 white family wealth.

FEDERAL HOME ENERGY ASSISTANCE

2017: 23,844 Heating/Cooling Bills covered

2018: 16,697 Heating/Cooling Bills covered

ENERGY BILLS EXCEEDED AFFORDABILITY

2017: $1,339 per household

2018: $1,812 per household

HOME ENERGY BURDEN: HOUSEHOLDS BELOW 50% OF FPL

2017
34% of
household income

2018
40% of
household income

ELECTRICITY

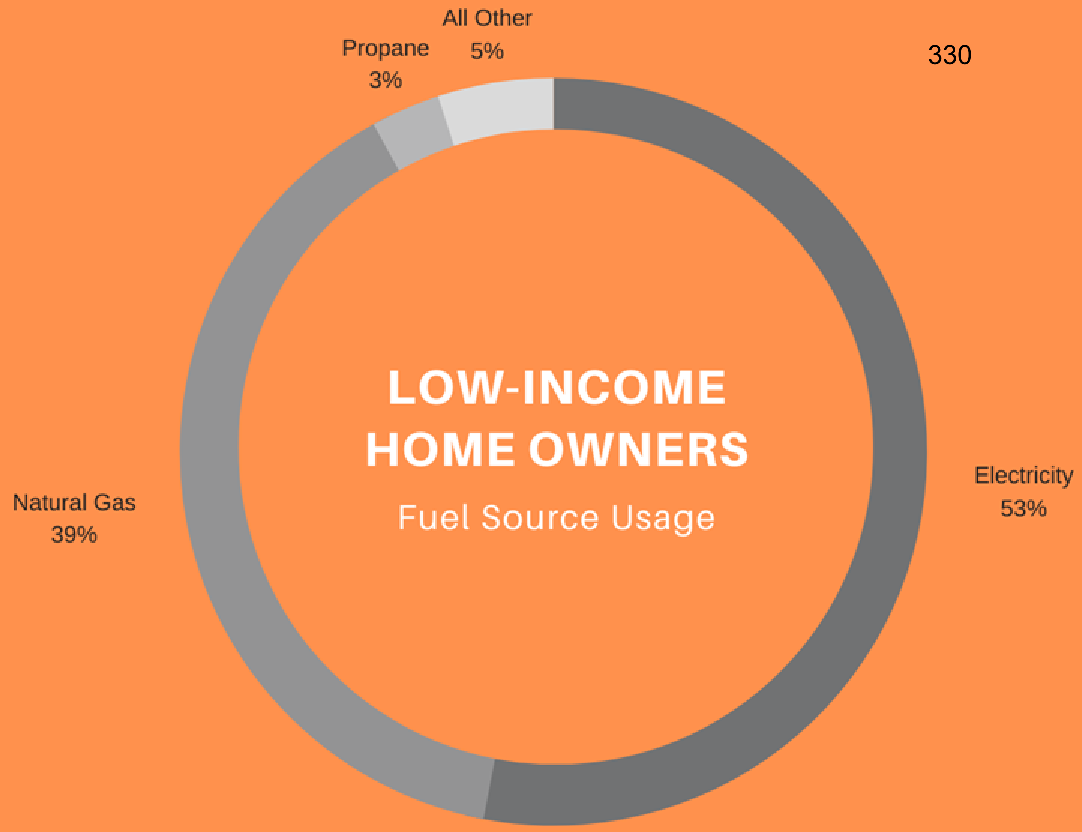
NATURAL GAS

FUEL OIL

PROPANE

ALL OTHER

TOTAL



ELECTRICITY

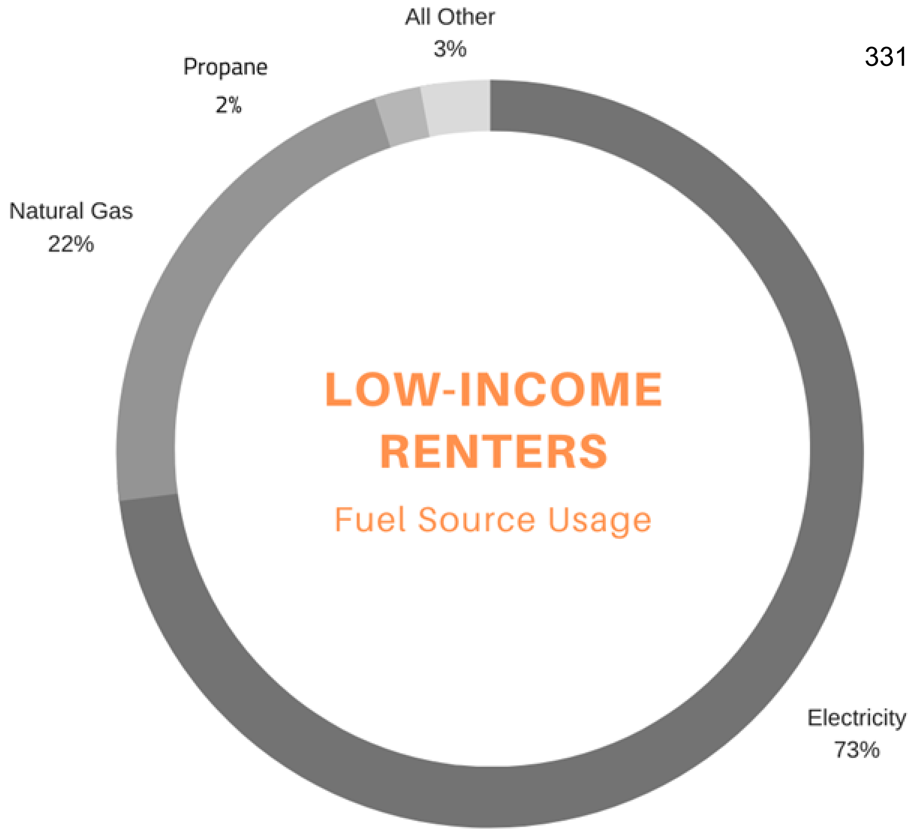
NATURAL GAS

FUEL OIL

PROPANE

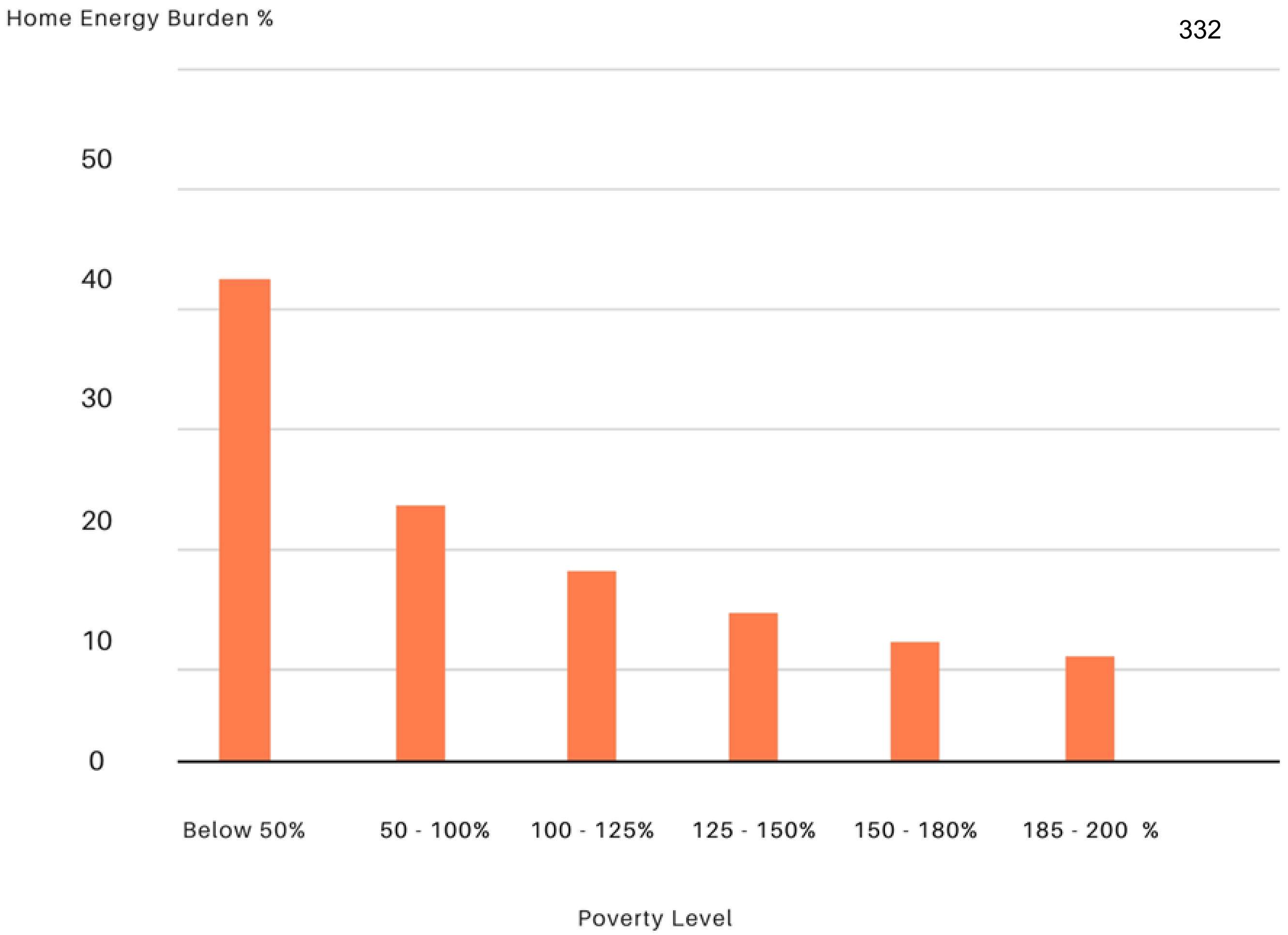
ALL OTHER

TOTAL 100%

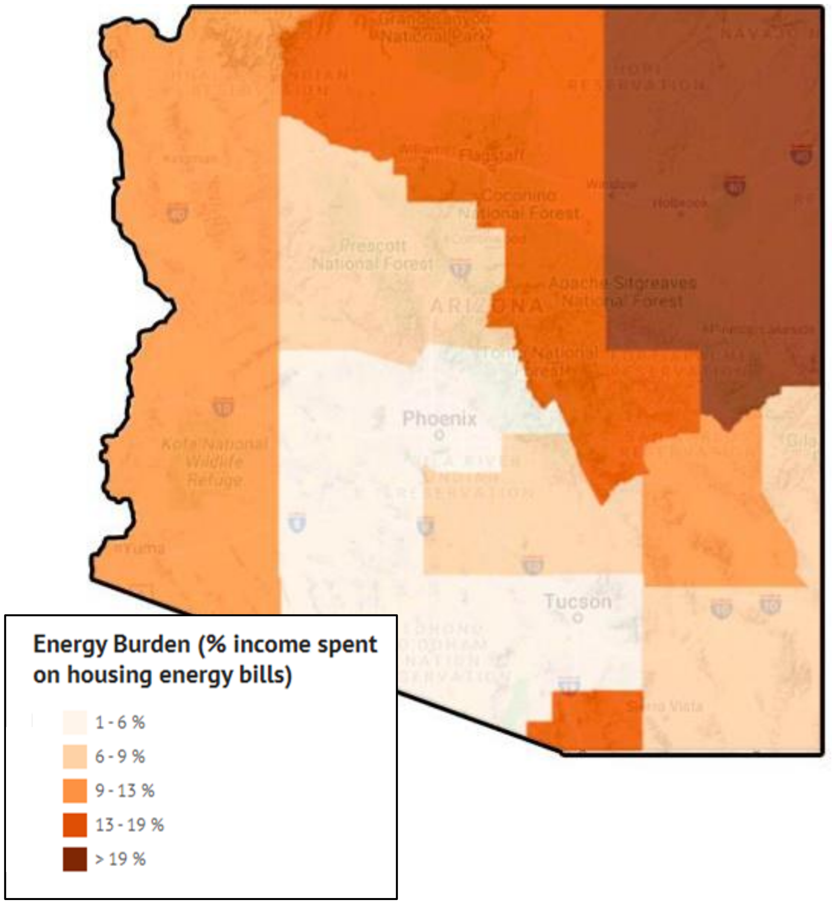


Energy Burden

Home energy is a crippling financial burden for low-income Arizona households. Arizona households with income below 50% of the Federal Poverty Level pay 40% of their annual income simply for their home energy bills.



Energy Burden Across Arizona



Energy Burden	County
5.28%	Pima
5.71%	Maricopa
6.10%	Pinal
6.96%	Greenlee
8.01%	Yavapai
8.50%	Cochise
10.75%	Mohave
10.94%	La Paz

Energy Burden	County
10.95%	Graham
11.47%	Yuma
13.46%	Coconino
14.19%	Gila
14.46%	Santa Cruz
49.57%	Navajo
66.50%	Apache

Query pulled from the NREL "Solar For All" Database, https://maps.nrel.gov/solar-for-all/?aL=6m-d90%255Bv%255D%3Dt&bL=clight&cE=0&lR=0&mC=38.870832155646326%2C-

Home Energy Affordability Gap

Federal fuel assistance program leaves many households uncovered

	Last Year	This Year
Gross LIHEAP Allocation ($000's)	$18,408	$18,651
Number of Households <150% FPL	686,900	671,003
Heating/Cooling Bills "Covered" by LIHEAP	23,844	16,697
Low-Income Households left "Uncovered"	663,056	654,306

Energy Efficiency as a Strategy to Avoid Disconnections in the First Place

SWEEP

Example drivers of high household energy burden

Type of driver	Examples
Physical	Inefficient and/or poorly maintained HVAC systems
	Heating system and fuel type
	Poor insulation, leaky roofs, and inadequate air sealing
	Inefficient large-scale appliances (e.g., refrigerators, dishwashers) and lighting sources
	Weather extremes that raise the need for heating and cooling
Economic	Chronic economic hardship due to persistent low income (see text box "Income Inequality and Energy Affordability")
	Sudden economic hardship (e.g., severe health event or unemployment)
Policy	Inability or difficulty affording the up-front costs of energy efficiency investments
	Insufficient or inaccessible policies and programs for bill assistance, weatherization, and energy efficiency for low-income households
	Certain utility rate design practices, such as high customer fixed charges, that limit the ability of customers to respond to high bills through energy efficiency or conservation
Behavioral	Lack of access to information about bill assistance or energy efficiency programs
	Lack of knowledge about energy conservation measures
	Increased energy use due to age or disability

Source: American Council for an Energy Efficiency Economy, Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low Income and Underserved Communities

Policies and programs for addressing high energy burden

Program type	Program	Funding source
Bill assistance	Low Income Home Energy Assistance Program (LIHEAP)	Federal and state taxpayers
	Other low-income bill assistance programs	Utility ratepayers; private contributions
	Modified rate design, rate discounts or waivers, and modified billing methods	Utility ratepayers
Weatherization	Weatherization Assistance Program (WAP)	Federal and state taxpayers
Energy efficiency	Low-income energy efficiency programs[1]	Utility ratepayers[2]

Source: American Council for an Energy Efficiency Economy, Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low Income and Underserved Communities

Benefits of Investing in Energy Efficiency in Low-Income Communities… Continued

Benefit recipient	Energy efficiency outcome	Resulting benefit
Communities	Lower electric and gas demand	Reduced environmental pollutants and improved public health
	Lower monthly utility bills due to avoided utility costs	More money spent in the local economy due to greater household disposable income, with higher local multiplier effect
		Poverty alleviation and increased standard of living
	Improvements in the efficiency of the housing stock	Local job creation through weatherization programs and energy efficiency providers and trade allies
		Improved quality of life
		Increased property values and preservation of housing stock

Source: American Council for an Energy Efficiency Economy, Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low Income and Underserved Communities

Barriers and Challenges to the Delivery of Energy Efficiency Services to Low- and Low-to -Moderate Arizonans

1) High upfront costs of energy efficiency investments
2) "Split incentives" between owners and renters
3) Lack of access to information to participate in efficiency programs
4) Lack of time or resources to participate in efficiency programs
5) Housing stock health, structural, and safety deficiencies
    - Major issues can render households ineligible
    - Minor issues can add to projects cost or challenge project cost-effectiveness
6) Reaching low-income customers
    - Utilities struggle to find ways to reach low-income households, where language barriers and time constraints may prevent program participation
    - Utilities may not always be perceived as helpful partners when interactions with them have previously been focused to payment and service disconnect notices

Best Practices for Improving the Effectiveness of Efficiency Services for Low- & Low-to-Moderate Income Arizonans

- Conduct market segmentation and offer targeted/tailored program offerings to reach these segments
- Accommodate health and safety measures through program design
- Prioritize efficiency measures that achieve deep savings
- Offer a comprehensive range of measures and services
- Cost-effectiveness reforms
- Form partnerships to better market and deliver services to hard-to-reach customers
- Develop programs targeted to affordable multifamily housing
- Provide financing options to households and building owners
- Leverage diverse funding sources to focus on comprehensive dual-fuel or fuel-neutral upgrades including health and safety measures
- Emphasize quality control and training
- Implement best practice programs recognized nationally for innovation, performance

Recommendations from the report, "Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low Income and Underserved Communities"

Highlights from Other Utilities: Duke Energy Neighborhood Energy Saver Program

- Uses a community approach to swiftly reduce energy bills for a large number of participants
- Targets low-income neighborhoods, working with local leaders to build neighborhood engagement and buy-in, and conducting energy assessments, energy-saving improvements, and participant education at no cost
- Census and other data are used to identify low-income neighborhoods
- After community buy-in is established, over the next 8–10 weeks, contractors conduct walk-through home energy assessments, install up to 20 energy-saving improvements in each participating home, and educate households about ways to further improve energy efficiency, all at no cost
- The program upgrades hundreds of homes in a cost- and time-efficient manner
- 70 percent participation rate is typical

Input for the Commission's Consideration on Next Steps for its Disconnection Rule-making

Arizona PIRG Education Fund

The Commission should define and establish a goal(s) to guide its rule-making process and related actions

- What are the Commission's ultimate goals:
    - Stopping all utility disconnections?
    - Stopping disconnections during extreme (hot or cold) weather conditions?
    - Protecting ratepayers?
    - Protecting public health?
    - Other?
    - Combination?
    - All of the above?
- **The Commission should solicit input from stakeholders to define and set its goals for its rule-making and other next steps**

The Commission should Implement the Key Activities Described in the Stakeholder Disconnection Workplan

- The workplan outlines 14 key activities to identify the concrete actions, policies, programs, and procedures that will protect the well-being of Arizona ratepayers and ideally strive to eliminate all utility disconnections

- The workplan was filed by filed by Wildfire, Arizona PIRG Education Fund, RUCO, and St. Vincent De Paul on June 20th, 2019, and developed with help from SWEEP

- Example workplan activities include:
  - Conduct a deep-dive analysis of disconnection data for the last five years; a demographic analysis; a housing and locational analysis; a market segmentation analysis; etc. to elucidate disconnection trends and understand who is being disconnected, influences on disconnection, and the impacts of disconnection
  - Establish risk factors and an associated framework to proactively identify customers vulnerable to disconnection and to recommend and implement a suite of concrete/proactive actions, policies, programs, and procedures to help ensure that at-risk customers never disconnect including recommendations for bill assistance, energy efficiency programs, energy education, etc. and for the selection of and enrollment in rate options

Additional Key Activities Described in the Stakeholder Disconnection Workplan

- Benchmark the disconnection policies of regulated electric utilities in Arizona against other utility policies nationally
- Review and recommend improvements to payment assistance options
- Review and recommend improvements to rate options including for the selection of and enrollment in those rate options
- Review and recommend improvements to energy efficiency programs and services targeted toward vulnerable and at-risk populations
- Review and recommend improvements to education efforts, including energy education efforts
- Review and provide recommendations on reconnection processes including reconnection fees and deposits
- Review and recommend disconnection communications and communication procedures,
- Establish goals, metrics and reporting around disconnection processes

The Commission should ensure any process, activities, and actions it pursues are oriented first toward solutions that mitigate the health and human impacts of disconnection, data-driven and supported by evidence, and collaborative

COVID-19: Utility Related Recommendations

The services provided by utilities are part of our daily routine. Arizonans use electricity for many purposes including to keep our food and medicine refrigerated, wash and dry our clothes, and charge our computers and phones. Arizonans use gas to cook and warm our homes. Arizonans use water to drink and bathe. Arizonans used telecommunications for work and school and to communicate with family and friends.

For years, many Arizonans have struggled to pay utility bills. Due to the public health warnings associated with COVID-19, many more Arizonans are working from home and taking classes online. Without at least temporary relief and clear communication, Arizonans are likely to face even greater challenges paying utility bills for the foreseeable future.

Although the Arizona Corporation Commission, utilities and non-profits cannot fix the crisis on our own, we can help alleviate at least some of the angst of ratepayers through mitigating reliability, safety and financial concerns and by visibly and frequently communicating the measures underway to protect consumers.

Below please find recommendations for the Arizona Corporation Commission, utilities and consumers and links to recent utility policies. Wildfire and the Arizona PIRG Education Fund are pleased that a number of utilities have proactively instituted policies to help consumers during this challenging time and urge others to follow suit.

Recommendations for the Arizona Corporation Commission

- Require a temporary disconnection moratorium for electric, gas, water, sewer and telecommunication utility services.
- Require a temporary moratorium on utility deposits and late fees.
- Require a minimum of an automatic six-month payment plan, with the ability to extend, for those falling behind on their utility bills.
- Require utilities to provide the opportunity for customers to switch rate plans with no penalties.
- Require utilities to provide customers, upon request, with information about the least-cost rate plan for their household due to estimated changes in usage.
- Require telecommunication companies to take and implement the "Keep Americans Connected Pledge".

- Require utilities to clearly, consistently and directly educate ratepayers about potential impacts of Time-of-Use and Demand Rate plans and the ability to switch rate plans with no penalties. Communication to ratepayers should happen over multiple channels including traditional and social media, bill statements, homepage of website, email and text messages (where consent has been granted) and in multiple languages including English and Spanish.
- Require utilities to actively promote financial assistance that is available to help pay utility bills.
- Require utilities to routinely provide updates to the docket stemming from COVID-19. Updates should include if there is a significant number of customers switching rate plans, a significant increase in the number of customer requests or other customer communication and status of arrearages and financial support available compared to the previous year.
- Protect Commission employees and the public through requiring non-essential personnel to work from home and by setting up video conferencing for meetings, workshops and other Commission business.

Recommendations for Utilities

- Implement a temporary disconnection moratorium.
- Implement a temporary moratorium on utility deposits and late fees.
- Implement a minimum of an automatic six-month payment plan, with the ability to extend, for those falling behind on their utility bills.
- Provide the opportunity for customers to switch rate plans with no penalties. Ensure a customer can reach customer service 24-7.
- Provide customers, upon request, with information about the least-cost rate plan for their household due to estimated changes in usage.
- If applicable, take the “Keep Americans Protected Pledge”.
- Clearly, consistently and directly educate ratepayers about potential impacts of Time-of-Use and Demand Rate plans and the ability to switch rate plans with no penalties. Communication to ratepayers should happen over multiple channels including traditional and social media, bill statements, homepage of website, email and text messages (where consent has been granted) and in multiple languages including English and Spanish.
- Actively promote financial assistance that is available to help pay utility bills.
- Routinely provide updates to the docket stemming from COVID-19. Updates should include if there is a significant number of customers switching rate plans, a significant increase in the number of customer requests or other customer communication and status of arrearages and financial support available compared to the previous year.
- Protect employees and the public through requiring non-essential personnel to work from home and by setting up video conferencing for meetings and other utility business.

Recommendations for Consumers

- Check with your utility on potential changes to their policies related to payments. See below for a list of recent utility policy changes.
- Identify potential changes in your utility usage. For instance, if there are now members of your household working from home or if there is a child or children taking classes from home a Time-of-Use Plan or Demand Rate plan may no longer be the least-cost option for your household.
- Contact your utility to explore the least-cost rate plan for your household due to estimated changes in usage. If you deem best, switch plans now with the potential to further adjust at the appropriate time (make sure your utility will allow an additional switch without penalty).
- If you are behind or anticipate having a hard time paying your electric bill, contact your utility as soon as possible to learn about financial assistance that may exist for your household. Ask your utility to set you up on a payment plan of six months, with the ability to extend if circumstances are warranted.
- For a list of organizations providing utility assistance, visit https://wildfireaz.org/find-help/energy-assistance/, email info@wildfireaz.org or call Wildfire at (602)604-0640.
- Contact the Arizona Corporation Commission at (602)542-4251 or file a complaint at https://bit.ly/2J9pmbN if you have a concern that your utility isn't addressing.
- Be on the lookout for utility and other scams. If in doubt, it is best to call your utility directly to ask questions or to make a payment. See the PIRG Education Fund's tips on Identifying Coronavirus Phishing Scams: How to protect your confidential information.
- Forward information directly from the utilities to family, friends, neighbors and colleagues.
- Follow our organizations for updates on COVID-19 and other consumer related issues. Facebook.com/StopPovertyBeforeItStarts and sign up for emails: info@wildfireaz.org Facebook.com/ArizonaPIRG and sign up for emails: https://bit.ly/2wwaIZs

Recent Utility Policy Changes & Statements

Please note the list below is not comprehensive and is subject to change. More information, particularly on what water companies in Arizona are doing, can be found at: https://bit.ly/2WMsYZt If you have a specific question or concern, please contact us through the information provided below. We also recommend you frequently check the website of the company for any policy updates.

Electric
Arizona Public Service
Salt River Project
Tucson Electric Power
UNS Energy Services
Grand Canyon State Electric Cooperative Association

Gas
Southwest Gas
UNS Energy Services

Water
Arizona Water Company
EPCOR
Global Water

Telecommunications
CenturyLink
Cox

Wildfire and the Arizona PIRG Education Fund recognize that many in our state are experiencing anxiety right now and that the COVID-19 situation is projected to get worse before it gets better. We appreciate the team effort underway in our state to provide updates and resources to Arizonans. We urge Governor Ducey and members of the Arizona legislature to provide funding for folks struggling to pay their utility bills during this time.

For More Information:

Cynthia Zwick
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czwick@wildfireaz.org

Diane E. Brown
Executive Director, Arizona PIRG Education Fund
dbrown@arizonapirg.org

Arizona Corporation Commission
1200 W. Washington St.
Phoenix, AZ 85007

April 27, 2020

Dear Chairman Burns and Commissioners,

RE: Docket Number AU-00000A-20-0094

We are writing in response to the establishment of the docket opened by Commissioner Marquez Peterson, "Commission Establishment of a Process to Track the Financial Impacts of COVID-19 on Regulated Utilities and Utility Customers in Arizona".

On April 24, 2020, our organizations, along with the Building Performance Association, filed a letter[1] related to the proposed Arizona Public Service (APS) COVID-19 Emergency and Temporary Customer Relief Package. Our letter respectfully requests that you require APS to provide additional information, such as by responding to the questions we raised in our letter before you vote on May 5.

According to our understanding, Commissioner Marquez Peterson seeks the largest utilities to provide financial impacts on both ratepayers and the respective utility – which will impact ratepayers - to the Commission as a consequence of COVID-19. We support Commissioner Marquez Peterson's request and appreciate her desire for Commissioners to request and gain additional information from all major utilities to make informed decisions.

The links provided in Commissioner Marquez Peterson's letter are helpful context to the situation facing utilities across the country and can provide valuable information, as our economy experiences the short-term and long-term effects of COVID-19. Each of us are in communication with other advocates in the region and across the country to learn and share best practices and ideas.

[1] "Joint Comments in Response to Arizona Public Service (APS) COVID-19 Emergency and Temporary Customer Relief Package," https://docket.images.azcc.gov/E000006108.pdf

Based on the above, we are providing slight modifications to questions previously posed to APS and request that you require all major utilities to respond with answers to this docket by COB on May 1:

1. What options have been explored to provide financial relief to customers?
2. In what categories is the utility experiencing net cost savings (e.g. operating) as a result of COVID-19? Per category, what are the estimated net cost savings through August 2020?
3. Does the utility anticipate revenue shortfalls as result of COVID-19 and if so, for what net amount per category through August 2020?
4. Does the utility anticipate coming to the Commission with a request to provide funds or additional funds for COVID-19 relief? If so, what will determine the need and what do you anticipate will be the source of those funds?
5. If applicable, how does the utility plan to track any expenditures made with relief funds?
6. If applicable, how does the utility plan to evaluate the use of relief funds?
7. If applicable, how does the utility plan to let ratepayers know about the availability of relief funds?
8. If applicable, how does the utility plan to determine which ratepayers are eligible to receive financial assistance?
9. If applicable, will the utility commit to providing a monthly update on relief support to this docket?

Below please find additional considerations related to financial impacts as you proceed in setting policies related to COVID-19. At a minimum, we think it is helpful to collect the following, including projected data, as applicable per major utility through at least August 2020:

- Ability to avoid or defer costly new capital investments or improvements. The information should be provided by item, along with a brief explanation and averted cost, even if only temporarily.
- Projected shifts in demand per customer class and corresponding ratepayer impacts.
- Projected shifts in ratepayer plans - estimated by the plan customers are likely to switch from to the plan customers are likely to switch to - due to shifts in demand, along with corresponding ratepayer impacts.
- Variations in energy efficiency program deployment as a result of stay at home orders or other issues related to COVID-19.
- Reduced work hours due to stay at home orders.
- Projected change in the number of customer service representatives available to assist customers with items such as evaluating and potentially changing their rate plan, financial help and payment plans.
- Estimated cost of establishing and maintaining 24-7 customer service.

- Overall and specific budget per utility (not utility departments) related to outreach and education. At a minimum, the budgets should be broken down by focus area – e.g., ability to switch rate plans, ability to save money through energy efficiency programs, ability to get help including financial assistance. Each utility should also explain its plan to track and evaluate the effectiveness of each component of its outreach and education efforts.
- Projected timeline and cost to set-up additional tracking systems. Each utility impacted by the disconnection moratorium established in June 2020 should docket what information they are currently collecting and how they are tracking information specifically related to COVID-19. During conversations with APS and TEP on the disconnection moratorium, we learned there can be substantial challenges and costs to creating new tracking systems. To get essential data in a consistent and timely manner, it is important that tracking systems are set up in a thoughtful and comprehensive manner. The systems must allow tracking per unique policy – heat-related moratorium, cold-weather moratorium, COVID-19 moratorium – as well as a comprehensive view that includes impacted ratepayers – whether duplicative or unique per policy. Commissioners, Commission Staff, and Stakeholders should have the opportunity to provide input into the tracking components prior to final implementation.
- Potential policy changes for Commission or utility consideration. Each utility should note their decisions and/or considerations underway for extending a disconnection moratorium, waiving late fees and related policies.

In regard to tracking, the National Consumer Law Center (NCLC) has noted in their April 2020 Issue Brief[2] that "while imperfect", the following states provide fairly good reporting on utility data. Here is information provided by NCLC:

> Ohio has one of the most detailed data reporting protocols in the country. In terms of the frequency and comprehensiveness of information collected and reported, the Ohio reporting template (PIPP Metrics Report Template) presents a good model.
>
> California's electric and gas investor-owned utility data reporting is also relatively comprehensive and informational. California requires electric and gas IOUs to report quarterly arrearages, disconnections, disconnection notices, restorations, and a range of other key data points separately for general residential customers, low-income customers participating in a low-income efficiency or discount program, and customers receiving the medical baseline" rate.
>
> In Pennsylvania, electric and gas IOUs have long reported key credit and collections data. The Pennsylvania Utility 'Commission's Bureau of Consumer Services issues an annual Universal Service Programs and Collections

[2]"The Need for Utility Reporting of Key Credit and Collections Data Now and After the Covid-19 Crisis", https://www.nclc.org/images/pdf/special_projects/covid-19/IB_Data_Reporting.pdf

> Performance Report delineating disconnections, reconnections, deferred payment agreements and other fundamental data points.
>
> Iowa electric and gas utilities have reported on some (but not all) critical credit, collections and energy security data points since 1999. A spreadsheet (Iowa Moratorium Report) shows time-series data and charts documenting general residential and low-income customer trends over the past 20 years. The spreadsheet includes a number of calculated fields that allow for rates of disconnections, arrearages, and other pertinent information to be displayed, which can be more useful than looking at raw numbers alone.

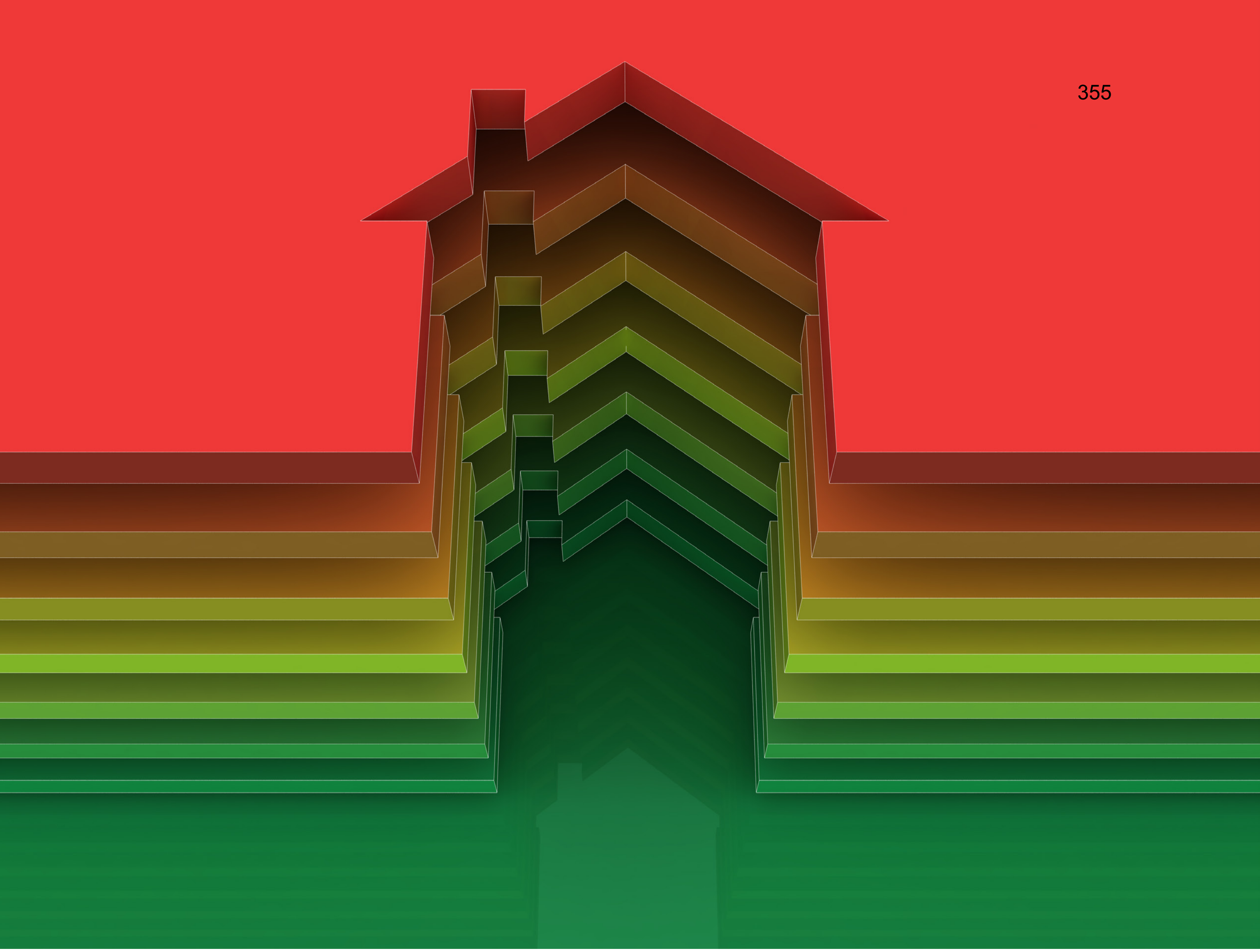
We share the desire for additional data and encourage Commissioners to require all large regulated utilities to answer questions we posed above. We also encourage Commissioners to direct Staff to draft a general order related to special accounting orders per Commissioner Marquez Peterson's letter to this docket.

Sincerely,

Diane E. Brown
Executive Director
Arizona PIRG Education Fund

Caryn Potter
Program Associate
Southwest Energy Efficiency Project (SWEEP)

Relevant Considerations



Grid-Interactive Efficient Buildings:
Providing Energy Demand Flexibility for Utilities in the Southwest

August 2019

SWEEP

SOUTHWEST ENERGY EFFICIENCY PROJECT

TABLE OF CONTENTS

I. INTRODUCTION

The electric utility system is rapidly changing due to retirement of coal generation, low natural gas prices, decreased prices for energy storage and renewable energy resources, and increased investments in energy efficiency. This is leading to flat or decreasing utility sales and changes to most utilities' generation portfolio, away from coal and toward renewable energy and in some places, natural gas-fired generation. At the same time, peak electric demand continues to grow on both the electric system as a whole and on certain portions of the transmission and distribution system. Increasing peak demand leads to the need for investments in both electric generation to serve the new load and the transmission and distribution infrastructure to deliver power to customers. To adapt to the changing industry and modernize the electric grid, electric utilities in the United States plan to invest over $1 trillion in new generation, distribution, and transmission infrastructure over the next 10 years.[1]

Changes to the electric industry are also creating new challenges for electric grid operators. For example, states with a high penetration of renewable resources, especially solar generation, are beginning to see very low or even negative electricity prices during times of the year when renewable energy generation is high and load is relatively low. At these times, renewable energy generation is reducing load to below the levels of baseload generation resources that are not easily turned off and on, leading to instances where there is more electricity generation than demand, causing negative electricity prices. However, once the sun goes down and solar generation decreases, utilities must have fast response resources that can rapidly fill the generation gap left by renewable resources coming offline. These issues are commonly referred to as the "duck curve".[2]

Buildings in the United States are a major driver of these trends as they consume approximately 75% of electricity.[3] However, buildings can also be a potential solution given that much of the electrical load in buildings is flexible and can be managed to operate at specific times and at different output levels.[4] By adding advanced controls and communications systems to building equipment, building managers and grid operators can adjust power consumption to meet grid needs through controlling existing equipment such as heating, ventilation, and air conditioning ("HVAC") systems, lighting, hot water heaters, and pool pumps. In addition, grid operators can now also utilize customer distributed energy resources such as solar photovoltaics, electric vehicle charging, and energy storage to manage peak loads and provide other value streams back to the grid.

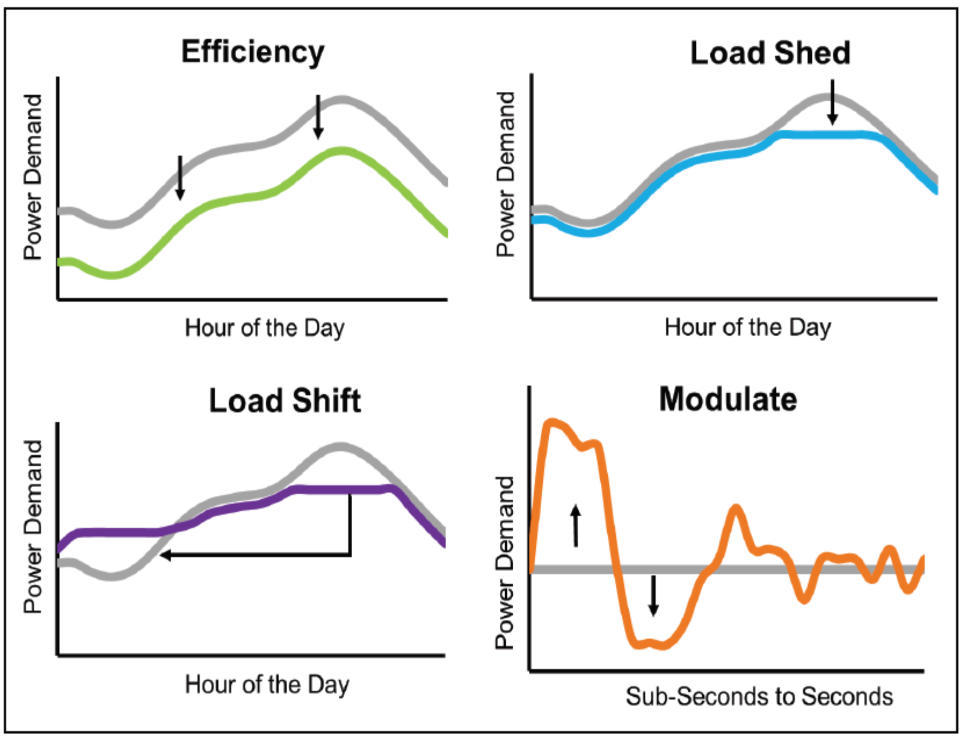
The Rocky Mountain Institute ("RMI") estimates that the demand flexibility available in buildings has the capability to reduce peak energy demand by 8% in the United States, avoiding $9 billion per year in utility capital investments. RMI also estimates that flexible buildings can supply an additional $4 billion per year in value to the electric grid by shifting energy usage to lower cost hours of the day and providing energy services back to the grid.[5]

[1] Dyson, Mark, James Mandel, et al. "The Economics of Demand Flexibility: How "flexiwatts" create quantifiable value for customer and the grid." Rocky Mountain Institute, August 2015.
[2] Lazar, Jim. Teach the "Duck" to Fly, 2nd Edition. Regulatory Assistance Project. February 2016.
[3] Energy Information Administration, Annual Energy Outlook 2018.
[4] Department of Energy, Buildings Technology Office "Grid-Interactive Efficient Buildings Factsheet." April 2019.
[5] Dyson, Mark, James Mandel, et al. "The Economics of Demand Flexibility: How "flexiwatts" create quantifiable value for customer and the grid." Rocky Mountain Institute, August 2015.

Building Demand Flexibility

According to the U.S. Department of Energy, there are four modes with which buildings can provide demand flexibility:[6]

1. **Efficiency:** the ongoing reduction in energy use while providing the same or improved level of building function.
2. **Load Shed:** the ability to reduce electricity use for a short time period and typically on short notice. Shedding is typically dispatched during peak demand periods and during emergencies.
3. **Load Shift:** the ability to change the timing of electricity use to minimize demand during peak periods or take advantage of the cheapest electricity prices. A shift may lead to using more electricity during the cheapest time period and using thermal or battery storage at another time period when electricity prices increase.
4. **Modulate:** the ability to balance power supply/demand or reactive power draw/supply autonomously (within seconds to sub-seconds) in response to a signal from the grid operator during the dispatch period.



Grid-integrated efficient buildings ("GEBs") can provide one or all of these services to the grid without affecting the comfort of building occupants or the functioning of the building. Energy efficiency is a key component of GEBs, as efficient buildings reduce the electricity consumed by the building during all hours of the year. In addition, efficient buildings may be more able to provide additional value to the grid by changing the timing of electricity usage. For example, many GEBs provide services to the grid through changing the timing and temperature set point of building cooling. A well-insulated, efficient building will maintain its temperature for a longer period during hot weather, providing a larger ability to shift the timing of energy usage relative to a poorly insulated building, without affecting the comfort

[6] U.S. Department of Energy, "Grid-Interactive Efficient Buildings Overview." April 2019.

of occupants.[7] Thus, efficient buildings have the ability to participate in longer-duration demand response (DR) events, creating more value to both the building owner and the electric grid.

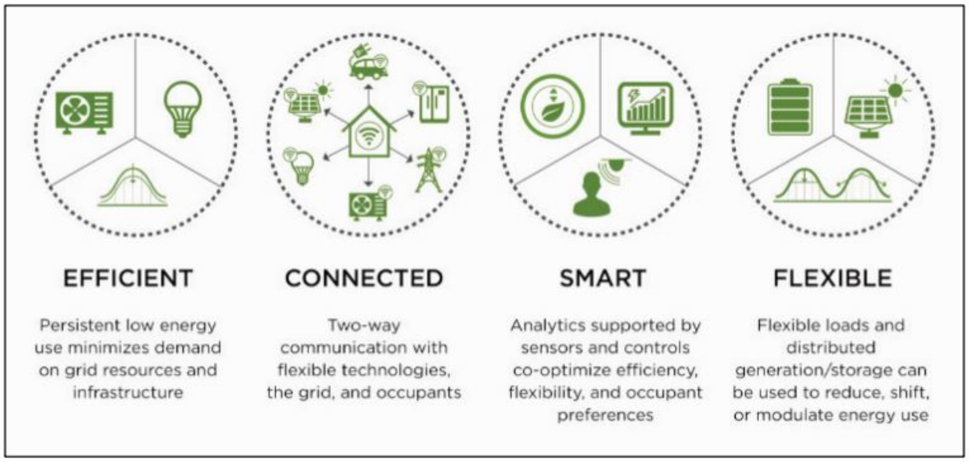
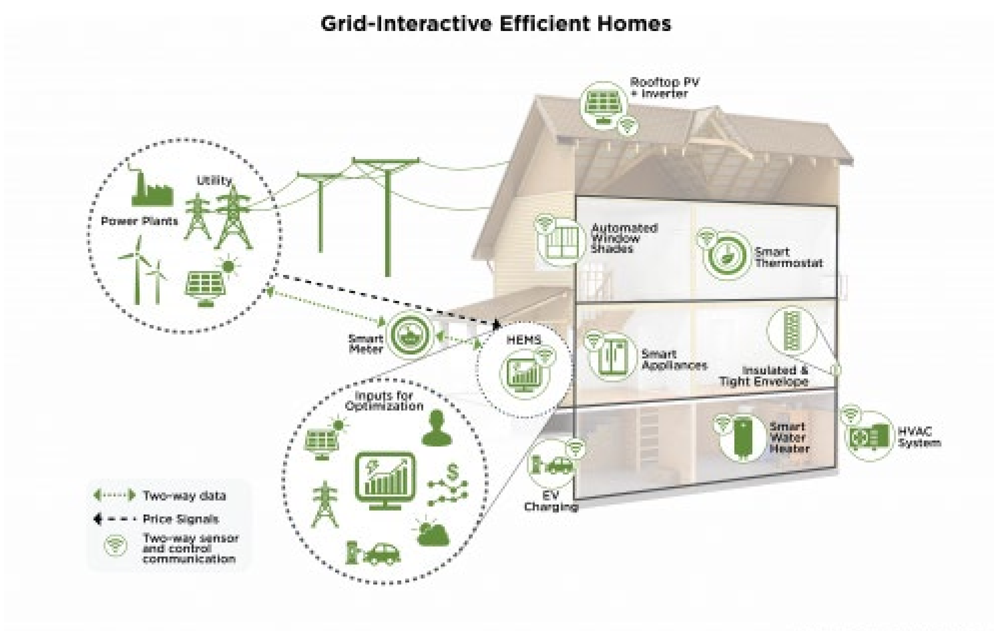


Figure 1. Characteristics of Grid-Interactive Efficient Buildings. Graphic: U.S. DOE

Buildings can provide additional value by changing the timing of load in response to grid signals by shedding, shifting, or modulating the load of the building. With its high and growing penetration of variable renewable generation, the Southwest states are at the forefront of efforts to utilize GEBs to help better control power demand and integrate high levels of renewable generation into the electric system at a reasonable cost.



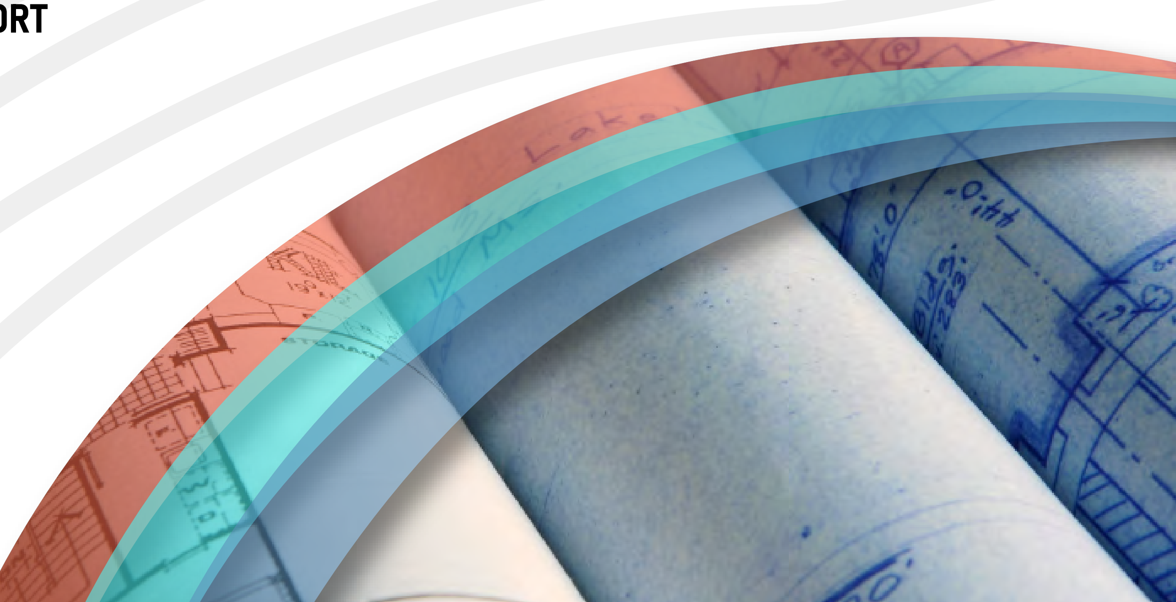
This report provides a summary of the residential and small commercial grid-interactive building demand-side management (DSM) programs at the major utilities in the Southwest, highlighting existing programs in the region that are using grid-interactive buildings as a resource to help with the integration of variable renewable generation and to provide other grid services that create value for customers. [8] While not meant to be exhaustive, this report attempts to highlight programs that are at the forefront of utilizing GEBs to provide value to the grid.

[7] Comments of the Alliance to Save Energy. Request for Information DE-FOA-0002070: Efficient and Flexible Building Loads. March 1, 2019.
[8] Our analysis examines utilities in Colorado, Utah, New Mexico, Arizona, and Nevada.

TRAINING THE WORKFORCE FOR HIGH-PERFORMANCE BUILDINGS:
ENHANCING SKILLS FOR OPERATIONS AND MAINTENANCE

BY ROHINI SRIVASTAVA, MOHAMMED AWOJOBI, AND JENNIFER AMANN

ACEEE RESEARCH REPORT
SEPTEMBER 2020



ACEEE
American Council for an Energy-Efficient Economy

Contents

Executive Summary

KEY FINDINGS

- Today's high-performance buildings place new skill and knowledge demands on facility managers, building operators, engineers, equipment installers, and other onsite technicians. Skill deficiencies among these professionals can prevent high-performance buildings from delivering on their promise, adversely impacting their energy savings, indoor environmental quality, cost effectiveness, and long-term viability.
- According to our survey of 111 building owners/managers, operators, tradespeople, technicians, and service providers, five categories of technical skills are essential for the high-performance buildings workforce. Ninety-two percent of respondents said **operations and maintenance** (O&M) skills are the most critical. O&M uses cost-benefit analysis to refine efficiency goals, optimize systems, and diagnose and correct problems before systems fail; it also involves operating and maintaining equipment, control, and automation systems.
- Other critical technical skills include **systems integration** (cited by 78% of respondents), **systems testing and evaluation** (78%), **data acquisition and analysis** (68%), and **system design and performance modeling** (42%). Critical thinking, communication, and teamwork were cited as the most essential nontechnical skills.
- Exemplary training programs are revealing the most effective approaches to training high-performance buildings professionals. Two general approaches are (1) "upskilling," or continuing education and certification programs for professionals who need to fill knowledge gaps, and (2) career-oriented training for new entrants to the field, including high school and community college students.
- Utilities, program administrators, and policymakers can take the following steps to begin addressing skills gaps: Establish skill and credentialing standards with the help of periodic job task analyses, reach out to high school students, integrate and coordinate training efforts to avoid duplication, create and promote a clearinghouse of curricula, and create building training and assessment centers at institutions of higher education.

Improving the energy efficiency of the U.S. building stock could reduce building-related carbon emissions by as much as 50%.[1] Upgrading existing buildings with energy efficiency technologies, incorporating smart controls, and electrifying remaining loads are key strategies that will make our buildings more efficient. However, the advanced technologies, greater systems integration, and expanded automation found in high-performance buildings place new demands on the staff who service them. Proper training of workers entering the field and continuing education for the existing workforce are both essential to achieving the energy efficiency, comfort, and other benefits these buildings are designed to

[1] Nadel, S., and L. Ungar. 2019. *Halfway There: Energy Efficiency Can Cut Energy Use and Greenhouse Gas Emissions in Half by 2050*. Washington, DC: ACEEE.

deliver. Although it is clear that building staff need skills beyond those taught in traditional building management and maintenance courses, what they need to know remains poorly defined.

Impacts of Workforce Skills Gaps

The skills gaps identified in this report have negative consequences for building owners and occupants alike. If a building's systems are improperly installed, commissioned, or maintained, the building will not function as intended, not only hindering its energy and indoor environmental performance but also dissuading customers from future investments in energy-efficient technologies, thereby slowing their adoption. Energy use may increase, negatively affecting the building owner's or leaseholder's ability to meet energy or sustainability goals. Other impacts include higher installation costs and compromised work quality. A building that operates outside its intended parameters will not reach its full potential to provide good indoor environmental quality, leading to occupant discomfort and reduced productivity.

Essential Building Performance Skills

According to interviews with experts and review of existing literature, five categories of technical skills are essential for the high-performance buildings workforce: **operations and maintenance (O&M), systems integration, systems testing and evaluation, data acquisition and analysis, and systems design and performance modeling**. According to the literature, expert interviews, and survey responses, the most critical skill set is building O&M, which includes the use of cost-benefit analysis to refine efficiency goals, optimize systems, and perform diagnostic and corrective procedures before a system fails; it also includes operating and maintaining equipment, control, and automation systems. As in other scientific and engineering fields, the workforce also needs training in nontechnical skills to perform effectively, the most essential being critical thinking, communication, and teamwork. These skills will only increase in importance as building technologies evolve and systems are integrated to optimize performance.

Skills Gaps

In contrast to the buildings workforce of the past, and as mentioned above, today's professionals must also be competent in data acquisition and analytics to ensure that high-performance buildings reach their full potential. Notably, we found a disconnect between building professionals and academics with regard to these critical skills. Further job task analyses can help develop training to ensure proficiency in data analytics. Our research also shows that building professionals need focused training in other key proficiencies: using cost-benefit analysis models to manage and influence building efficiency decisions; optimizing systems; ensuring cybersecurity; managing and programming multiple building systems including HVAC, lighting, building automation, and energy management systems; and performing commissioning, retrocommissioning, and energy audits. More work is needed to map out the skills that will improve high-performance building operations and identify potential pathways to bridge the gaps in skills currently found in the industry.

APPROACHES TO WORKFORCE TRAINING

Given the urgent need for expanded training in building performance skills, it is fortunate that several exemplary training programs are demonstrating which approaches can work well. These programs provide technical education on high-performance technologies and operations, combining in-class instruction, hands-on learning, and practical training in the field or in the lab. There are two general approaches to teaching these skills: (1) "upskilling," or continuing education and certification programs for building professionals who need to fill knowledge gaps and learn about new technologies and practices, and (2) career-oriented training for new entrants to the buildings workforce. A number of utilities, labor unions, and other parties offer continuing education courses, seminars, and certifications that can meet the need for highly specialized training in areas such as cybersecurity and systems programming and integration. Career training programs such as apprenticeships and those offered in community colleges and universities can help develop building performance skills from the ground up and address needs in fields such as data analytics and systems measurement and verification.

RECOMMENDATIONS

We recommend the following actions to develop the necessary workforce for high-performance buildings:

- *Establish skill and credentialing standards* that utilities and building service providers can promote; this will ensure that building operators and technicians have the requisite skills and will help scale effective training programs. Conduct periodic job task analyses to help identify workforce needs and current training opportunities and to inform decision making on educational needs.
- *Integrate training approaches* based on an understanding of the building staff's skill deficiencies; identify short- and long-term training opportunities to bridge skills gaps. Coordinate training initiatives based on best practices in workforce development to avoid duplication of efforts and ensure that high-quality, up-to-date programs are offered.
- *Reach out to high school students* to increase their awareness of opportunities in the industry. Develop resources for educators and guidance counselors to help them understand career pathways and the skills that are needed to succeed.
- *Coordinate training efforts and share best practices* to avoid duplication of efforts and ensure high-quality programs are offered throughout the country to allow greater dissemination of key skills.
- *Establish and promote a clearinghouse of curricula, training programs, and certifications* to reduce confusion around which competencies should be acquired and where the necessary training can be obtained.
- *Create building training and assessment centers* at institutions of higher learning that can educate and train engineers, building scientists, and other professionals in efficient building design and operations and commercial building energy assessments.

Making Sense of Energy Storage

How Storage Technologies Can Support a Renewable Future

ENVIRONMENT AMERICA
RESEARCH & POLICY CENTER

FRONTIER GROUP

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Executive Summary

America must shift away from fossil fuels and towards clean, renewable sources of energy in order to protect our air, water and land, and to avoid the worst consequences of global warming. Renewable energy sources, such as wind and solar power, are virtually unlimited and produce little to no pollution. With renewable energy technology improving and costs plummeting, it is now possible to imagine a future in which all of America's energy comes from clean, renewable sources.

The availability of wind and solar power, however, varies by the hour, day and season. To repower our economy with clean energy, we need an electric grid that is capable of incorporating large volumes of variable renewable resources.

Energy storage technologies can be an important part of that electric grid of the future, helping to assure reliable access to electricity while supporting America's transition to 100 percent renewable energy. To get the most benefit out of energy storage, however, policy-makers and the general public need to understand how energy storage works, where and when it is necessary, and how to structure public policy to support the appropriate introduction of energy storage.

Energy storage can make a valuable contribution to our energy system.

- Energy storage can capture renewable energy produced in excess of the grid's immediate needs for later use. In California, solar and wind energy plants were forced to halt production more than one-fifth of the time during 2016 because the power they produced was not needed at that moment.[1]

- Energy storage can help utilities to meet peak demand, potentially replacing expensive peaking plants.

- Energy storage can extend the service lifetime of existing transmission and distribution infrastructure and reduce congestion in these systems by providing power locally at times of high demand.

- Energy storage can improve community resilience, providing backup power in case of emergency, or even allowing people to live "off the grid," relying entirely on clean energy they produce themselves.

- Energy storage can provide needed ancillary services that help the grid function more efficiently and reliably.

Energy storage is likely to be most effective when used as part of a suite of tools and strategies to address the variability of renewable energy. Other strategies include:

- **Widespread integration of renewable energy into the grid:** Increasing the number and geographic spread of renewable generators significantly reduces their collective variability by making it likely that a temporary shortage of generation in one area will be balanced by solar or wind energy production elsewhere.

- **Weather forecasting:** Having advance knowledge of when wind and solar availability is likely to rise or fall allows energy providers to plan effectively. New England's Independent System Operator (ISO) lists having access to detailed wind speed forecasts five minutes ahead as one of three requirements for making wind energy entirely dispatchable throughout the region.[2]

- **Energy efficiency:** Using less energy, particularly during times of greatest mismatch of renewable energy supply and demand, can reduce the need for backup energy sources. The American Council for an Energy-Efficient Economy has found that if a utility reduces electricity consumption by 15 percent, peak demand will be reduced by approximately 10 percent.[3]

- **Demand response:** Systems that give energy companies the ability to temporarily cut power from heaters, thermostats and industrial machinery when demand peaks – and provide financial incentives for consumers who volunteer to have their power curtailed – can reduce the risks posed by variability.[4] Studies have found that demand response can maintain the reliability of highly intermittent 100 percent renewable energy systems, often at a fraction of the cost of batteries.[5]

- **Building for peak demand:** Much like grid operators have done with conventional combustion power plants, it may make sense to build more renewable energy capacity than is typically needed in order to meet energy needs during times of highest demand. One research study found that the most affordable way to meet 99.9 percent of demand with renewable sources involved generating 2.9 times more electricity than average demand, while having just enough storage to run the grid for nine to 72 hours.[6]

  A number of researchers have outlined ways that the U.S. can be mostly or entirely powered by renewable energy. Energy storage figures into these different scenarios in a variety of ways. (See Table ES-1.)

Many types of energy storage technologies can help integrate renewable energy into America's energy system.

- **Thermal storage** stores energy in very hot or very cold materials. These systems can be used directly for heating or cooling, or the stored thermal energy can be released and used to power a generator and produce electricity. Even pre-heating hot water during periods of high renewable energy production or low demand can be considered a form of thermal storage.

- **Utility-scale batteries** can be located along the electricity distribution or transmission system, providing power during times of peak demand, aiding with frequency regulation on the grid, and absorbing excess renewable energy for later use.

- **Residential and commercial batteries** located "behind-the-meter" can provide backup power during power outages, and have the potential to be aggregated into a larger network and controlled by a utility to support the reliability of the grid. Electric vehicle batteries could also someday be integrated into the grid, charging at times when renewables are available and powering homes and businesses at times when demand is high.

- **Pumped-storage hydropower,** currently the most common and highest capacity form of grid-connected energy storage, works by pumping water from a lower reservoir, such as a river, to a higher reservoir where it is stored. When electricity is needed, the water in the higher reservoir is released to spin turbines and generate electricity.

- **Compressed air energy storage** works by compressing air and storing it in underground reservoirs, such as salt caverns. When electricity is needed, the air is released into an expansion turbine, which drives a generator.

- **Flywheels** use excess electricity to start a rotor spinning in a very low-friction environment and then use the spinning rotor to power a generator and produce electricity when needed. These systems have a variety of advantages – they require little maintenance, last for a long time and have little impact on

Table ES-1. The Role of Energy Storage in Various High Renewable Energy Blueprints

Author	Year	Scenario	Energy Sources Included	Role of Energy Storage	Stratefies Used Other than Storage
The White House[7]	2016	80% reduction in U.S. GHG emissions compared to 2005 levels, by 2050 (no carbon capture scenario)	Wind, solar, biomass, hydropower, geothermal (plus nuclear and natural gas)	Highlights reducing the cost and increasing the storage capacity of batteries as an important goal. Storage also plays a role in increasing grid flexibility.	Energy efficiency, demand response
MacDonald, et al.[8]	2016	U.S. electric grid is roughly 63% renewable, 30% natural gas and 7% nuclear in 2030 (low cost renewables case)	Wind, solar, hydropower (plus nuclear and natural gas)	Not included in model, due to cost.	Geographic diversification – electric grid is modeled as one system across the continental U.S. instead of regionally divided systems
Jacobson, et al. – two studies[9]	2015	100% renewable energy use in the U.S. in 2050	Wind, solar, geothermal, tide, wave, hydropower	Concentrating solar power (CSP) storage, pumped-storage hydropower, hydrogen, and thermal storage are used in all sectors. Batteries are only relied on for transportation, to reduce costs.	Energy efficiency, demand response
Greenpeace[10]	2015	100% renewable energy use globally in 2050	Wind, solar geothermal, biomass, ocean, hydropower	Hydrogen and synthetic fuels used as fuel sources; CSP built after 2030 incorporates storage; a combination of other types of energy storage used to store excess production and provide backup during shortages.	Energy efficiency, demand response, weather forecasting
Williams, et al.[11]	2015	U.S. electric grid is >80% renewable in 2050 (high renewables case)	Wind, solar, geothermal, hydropower	Used minimally to help balance supply with load. Hydrogen and synthetic natural gas are most used for balancing.	Energy efficiency, demand response
Budischak, et al.[12]	2012	Electric grid equivalent to 1/5 of U.S. electricity demand is 99.9% renewable in 2030	Wind, solar	Uses three types of energy storage: batteries, hydrogen and grid-integrated vehicles. They only need enough of these technologies to run entirely on storage for 9 hours, 72 hours, and 22 hours respectively.	Overbuilding renewables

the environment – but have limited power capacity.

Developing technologies, including hydrogen and synthetic natural gas, have the potential to offer unique benefits and may become important tools in the future for energy needs that are currently difficult to serve with electricity.

Energy storage has been growing rapidly in recent years and that growth is projected to continue.

- There is six times more energy storage capacity (excluding pumped-storage hydropower) in 2017 than in 2007 (see Figure ES-1).[13]

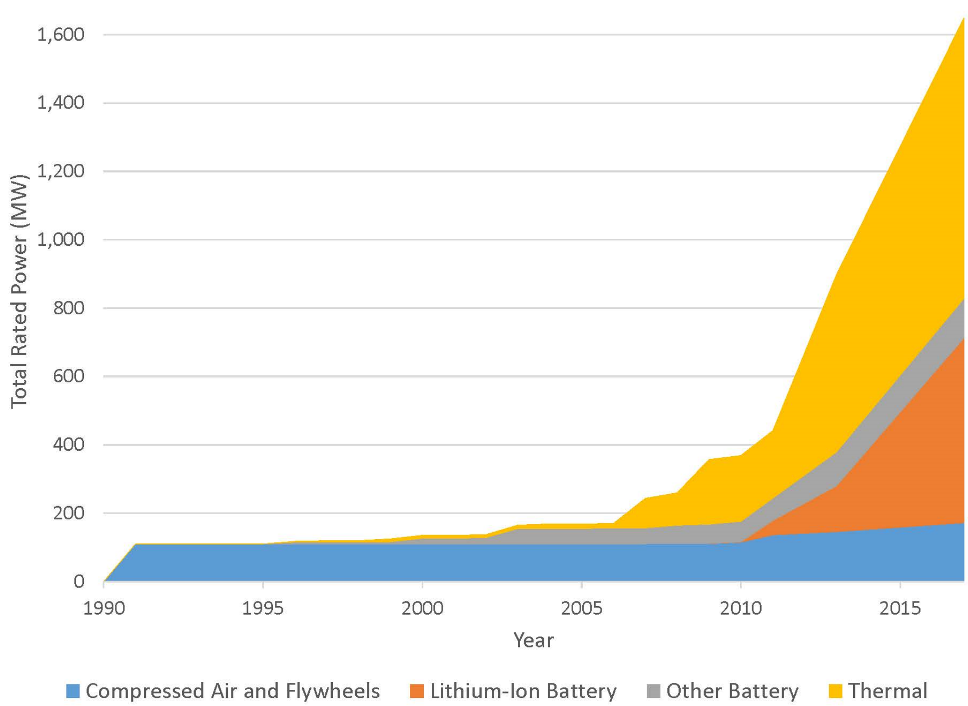
- GTM Research, an electricity industry analysis firm, predicts that the energy storage market will be 11 times larger in 2022 than it was in 2016.[14]

Energy storage is likely to become increasingly important and valuable in the years ahead, as a result of:

- **Falling costs:** The cost of energy storage has been declining rapidly, and this trend is expected to continue. Over the next five years, average costs are projected to fall 19 to 49 percent for batteries, and 23 to 37 percent for flywheels.[16]

- **Increasing renewable energy adoption:** The U.S. Energy Information Agency (EIA) expects that solar and wind capacity will increase by almost 20 percent in the two-year period from 2017 to 2018.[17]

Figure ES-1. Total Stacked Capacity of Operational U.S. Energy Storage Projects over Time, Excluding Hydropower[15]



- **New grid service markets:** Utilities are starting to recognize the value that energy storage can offer for purposes other than renewable energy integration.

- **Public policies:** The federal Investment Tax Credit for residential solar system can be applied to energy storage installed at the same time, and a new bill introduced in the Senate would create a tax credit for standalone storage as well.[18] A number of state policies supporting energy storage have been adopted in recent years: California, Oregon and Massachusetts have all passed laws setting energy storage targets, and similar proposals were passed by state legislatures in New York and Nevada in 2017.[19]

Smart policies will be key to allowing the energy storage market to continue to grow and support the nation's transition to a clean energy future. Policymakers should:

- Clarify existing grid connection and permitting policies to remove barriers to installation and deployment of energy storage;

- Design energy markets to capture the full value of energy storage and all the services these technologies can provide;

- Incentivize homes and businesses to adopt storage, which can increase resilience and provide benefits to the grid as a whole;

- Set storage benchmarks and encourage utilities to build and utilize energy storage throughout their system.

American Lung Association®
State of the Air

2020

State of the Air

Contents

The State of the Air 2020

The "State of the Air" 2020 found that, in 2016-2018, more cities had high days of ozone and short-term particle pollution compared to 2015-2017 and many cities measured increased levels of year-round particle pollution.

2020 marks the 50th anniversary of the Clean Air Act, the landmark law that has driven dramatic improvements in air quality over its history. This is critical because far too many communities reported air pollution that still threatens health, and climate change impacts continue to threaten to progress. Further, harmful revisions and setbacks to key protections currently in place or required under the Act threaten to make air quality even worse in parts of the country. "State of the Air" 2020 shows that we must not take the Clean Air Act for granted.

Too many cities across the nation experienced more ozone and more particle pollution in 2016-2018. Many reached or tied their highest levels ever.

The "State of the Air" 2020 report shows that too many cities across the nation increased the number of days when particle pollution, often called "soot," soared to often record-breaking levels. More cities suffered from higher numbers of days when ground-level ozone, also known as "smog," reached unhealthy levels. Many cities saw their year-round levels of particle pollution increase as well.

The "State of the Air" 2020 report adds to the evidence that a changing climate is making it harder to protect human health. The three years covered in this report ranked among the five hottest years on record globally. High ozone days and spikes in particle pollution followed, putting millions more people at risk and adding challenges to the work cities are doing across the nation to clean up.

The 2020 report—the 21st annual release—uses the most recent quality-assured air pollution data, collected by the federal, state and local governments and tribes in 2016, 2017 and 2018. The "State of the Air" 2020 report looks at levels of ozone and particle pollution found at official monitoring sites across the United States in those years. For comparison, the "State of the Air" 2019 report covered data from 2015, 2016 and 2017.

The report examines fine particle pollution (particulate matter smaller than 2.5 microns in diameter, also known as $PM_{2.5}$) in two separate ways: averaged year-round (annual average) and short-term levels (24-hour). For both ozone and short-term particle pollution, the analysis uses a weighted average number of days that allows recognition of places with higher levels of pollution. For the year-round particle pollution rankings, the report uses averages calculated and reported by the U.S. Environmental Protection Agency (EPA). (The full "State of the Air" 2020 methodology is included in a later chapter.)

Overall Trends

The "State of the Air" 2020 found that, in 2016-2018, millions more Americans were living in communities impacted by unhealthy levels of pollution in the form of more unhealthy ozone days, more particle pollution days and higher annual particle levels than was found in previous reports.

Nearly five in ten people—150 million Americans or approximately 45.8 percent of the population—live in counties with unhealthy ozone or particle pollution (with at least one F). That represents an increase from the past three reports: it's higher than the 141.1 million in the 2019 report (covering 2015-2017), 133.9 million in the 2018 report (covering 2014-2016) and 125 million in the 2017 report (covering 2013-2015). **More than 20.8 million people, or 6.4 percent of the population, live in the 14 counties that failed all three measures.**

Nearly five in 10 people live where the air is unhealthy.

Los Angeles remains the city with the worst ozone pollution in the nation, as it has been for 20 years of the 21-year history of the report. **Bakersfield, CA,** returned to the most-polluted slot for year-round particle pollution, while **Fresno-Madera-Hanford, CA,** returned to its rank as the city with the worst short-term particle pollution.

This shows growing evidence that a changing climate is making it harder to protect human health. All three years ranked among the five hottest years in history, increasing high ozone days and widespread wildfires, putting millions more people at risk and adding challenges to the work cities are doing across the nation to clean up. Rollbacks of EPA cleanup rules and reduced Clean Air Act enforcement are further adding to these air quality challenges.

This marks the fourth report in a row that worsening air quality threatened the health of more people, despite other protective measures being in place. Climate change clearly drives the conditions that increase these pollutants. The nation must do more to address climate change and to protect communities from these growing risks to public health.

The Clean Air Act must remain intact and enforced to enable the nation to continue working to protect all Americans from the dangers of air pollution. As the nation celebrates the 50th anniversary of the Clean Air Act this year and the dramatic improvements in air quality over its history, everyone must ensure that the Clean Air Act's tools remain in place, funded and followed in order to protect the public.

The Lung Association will continue to champion the Clean Air Act and push for clean air for all, defending Americans against proposals to reverse and reduce protections in place and supporting new efforts to curb harmful pollution.

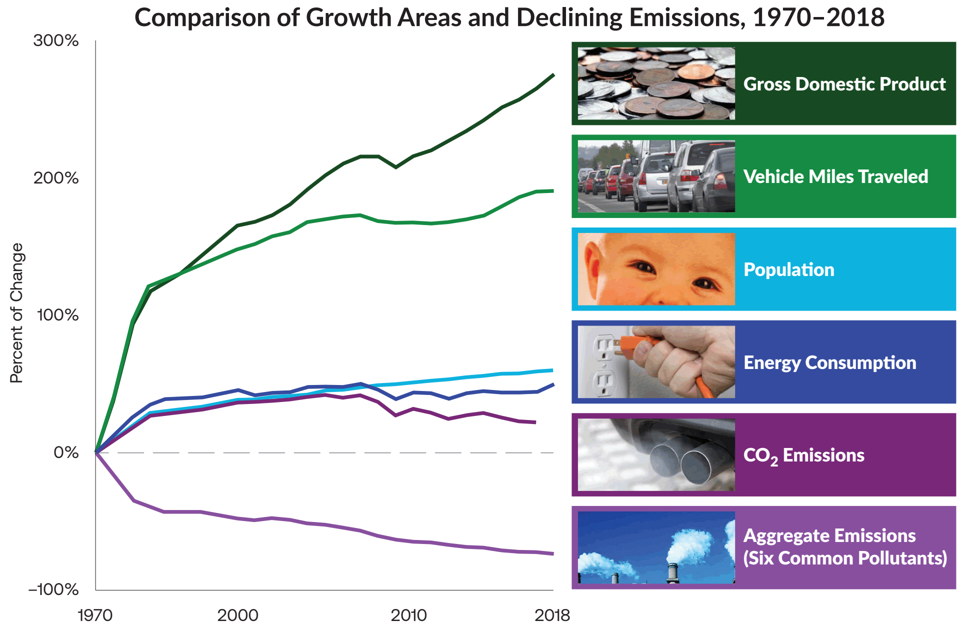


Figure 1: Air pollution emissions have dropped steadily since 1970 thanks to the Clean Air Act. Source: U.S. EPA, Air Trends: Air Quality National Summary, 2019.

Ozone Pollution

Far more people suffered unhealthy ozone pollution in 2016-2018 than in the last three reports. In 2016-2018, more than 137 million people lived in the 205 counties that earned an F for ozone.

That is significantly higher than in the 2019, 2018 and 2017 reports and is the highest since the 2016 report. This trend shows strong evidence of the impacts on air quality from the warmer years also reported in this period. Of the ten most polluted cities, six did worse than in the 2019 report, including some of the nation's largest metropolitan areas.

Why? Increased heat. The three years in this report were three of the five warmest on record in the United States: the year 2016 remains the warmest year on record, while 2017 is now the fourth warmest, and 2018 ranked fifth warmest. Warmer temperatures make ozone more likely to form and harder to clean up.

Changes in where ozone is worst in the U.S. continue a trend seen in the past four reports, where increased oil and gas extraction in the Southwest and cleanup of power plants in the eastern U.S. have shifted the cities that experienced the greatest number of unhealthy air days.

Ozone rankings are all based on unhealthy air days as recorded using the Air Quality Index adopted with the 2015 national air quality standard for ozone. In 2018, EPA officially designated all or parts of the 25 most polluted cities as “nonattainment” areas for that ozone air quality standard. That action requires these areas to take steps to clean up the sources of pollution going forward.

Los Angeles remains at the top of the list of most polluted cities for ozone, as it has been for all but one of the 21 reports, despite the metro area’s continued fight against ozone. Los Angeles-Long Beach also recorded more unhealthy ozone days in this report, measured by weighted average.

In addition to Los Angeles, 13 others among the 25 cities with the worst ozone pollution each had a higher weighted average of unhealthy days in 2016-2018, including some of the nation’s largest metropolitan areas: Phoenix, Las Vegas, Denver, Salt Lake City, Chicago and Milwaukee. Many smaller cities on that list also suffered from more ozone: Visalia, CA; Bakersfield, CA; El Centro, CA; El Paso-Las Cruces, TX-NM; Chico, CA; Fort Collins, CO; and Sheboygan, WI.

Eleven of the 25 cities with the worst ozone pollution had fewer unhealthy ozone days on average in 2016-2018. Those included San Jose-San Francisco-Oakland and Dallas-Fort Worth, each of which reached its fewest unhealthy ozone days ever. Other cities that had fewer high-ozone days included Fresno; Sacramento; San Diego; New York-Newark; Redding-Red Bluff, CA; Houston; Washington-Baltimore; Philadelphia; and Hartford, CT.

Regional Differences. Only seven cities among the worst for ozone are east of the Mississippi River, including the New York City metro area, where Fairfield County, CT, suffers from the highest levels in the eastern U.S. Others in the Northeast and Mid-Atlantic in the 25 most-polluted list are Washington-Baltimore; Philadelphia; and Hartford, CT. The Midwest has three: Chicago; Sheboygan, WI and Milwaukee. For the first time, with Atlanta’s improvement, no city in the Southeast has any city on the most-ozone-polluted list.

Cities in the West and the Southwest continue to dominate the most-ozone-polluted list. California retains its historic distinction, as it is home to 10 of the 25 most polluted cities. The Southwest continues to fill most of the remaining slots, with eight of the 25 cities, including three in Texas—Houston, El Paso, and Dallas-Fort Worth. Colorado has two—Denver and Fort Collins. Arizona, Nevada and Utah each have one.

The findings show the continued impact of transported pollution that moves ozone and ozone precursors across state lines. For example, emissions generated in Chicago cross Lake Michigan to reach Sheboygan, WI. Fairfield County, CT, remains the county with the highest ozone in the eastern half of the nation because of the transported ozone and ozone precursors from upwind states.

Short-Term Particle Pollution

More cities experienced more days of spikes in particle pollution, compared to the 2019 report. Twenty-two of the 25 most polluted cities had more such days on average in the 2020 report. Many cities reached their highest number of such days ever reported.

More people experienced unhealthy spikes in particle pollution than in the last three reports. More than 53.3 million people suffered those episodes of unhealthy spikes in 86 counties where they live. In the 2019 report, the total was approximately 49.6 million people who experienced too many unhealthy days; in the 2018 report, approximately 35.1 million people; and in the 2017 report, approximately 43 million people.

Why? Wildfires in 2017 and 2018, especially in California, were a main reason for many of these spikes. In the western U.S., climate change has made more likely the conditions of heat and drought that promote wildfire hazards. In some communities, wood smoke from home heating, especially when worsened by stagnant air masses known as inversions, has also contributed to high levels of particle pollution.

Nine of the ten most polluted cities had more days when particle pollution reached unhealthy levels; four of those reached their worst exposure ever recorded. Of the 25 most polluted cities, 22 had more days on average in this year's report, with nine cities reaching their highest number of days on average ever recorded.

Fresno-Madera-Hanford, CA, returns to rank as the #1 most polluted city for short-term particle levels. This marks the third time Fresno-Madera-Hanford has ranked at the top in this category; the last period was from 2011-2013, covered in the 2015 report. Bakersfield, which had been ranked in that spot for eight of the last ten reports, shifted to the 2nd most polluted city.

Nine cities had their highest-ever weighted average number of days with spikes in particle levels: Fairbanks, AK; Yakima, WA; Redding-Red Bluff, CA; Phoenix, AZ; Spokane-Spokane Valley-Coeur d'Alene, WA-ID; Chico, CA; Salinas, CA; Santa Maria-Santa Barbara, CA; and Las Vegas, NV.

> Just as people move around, so too does harmful pollution. Wildfire smoke is just one example of pollution threatening health far from the source.

Showing the impact of wildfires, this year's report marks the second year that Santa Maria-Santa Barbara, CA, showed up on the list of the most polluted for short-term particle pollution. Prior to the 2019 report, this city had been on the list of cleanest cities in the nation for the previous six years for the same pollutant.

Twelve other cities on the most-polluted list also suffered from more days with unhealthy levels of particle pollution. These include Bakersfield; San Jose-San Francisco; Los Angeles; Salt Lake City, UT; Sacramento; Visalia, CA; Logan, UT; Medford-Grants Pass, OR; El Centro, CA; Eugene, OR; Reno, NV; and Portland, OR.

Only three of the 25 most polluted cities improved and had fewer unhealthy air days on average than in the 2019 report. Though it improved from its worst performance in last year's report, Missoula, MT, remained among the nation's 10 most polluted cities. Two other cities on the list had fewer unhealthy days on average: Seattle and Pittsburgh.

In California, Montana, Oregon and Washington, extended wildfires increased the days when PM levels spiked during 2016-2018. The Los Angeles metro area had two days when levels spiked to "hazardous," the highest, "maroon" level in the Air Quality Index. The Chico, CA, metro area also recorded two hazardous days in Butte County, reaching its highest ever short-term weighted average. Eugene, OR, and rural counties Mendocino County, CA, Okanagan County, WA and Gallatin County, MT, each reached one hazardous day.

Wildfires are not the only source of high particle pollution days. Other contributing sources include wood stove use (especially in Fairbanks, AK), older diesel vehicles and equipment, and industrial sources (as in Pittsburgh, PA). Changes in weather patterns can create atmospheric inversions that trap particles in place, leading to days with spikes.

Pittsburgh is the only city in the 25 most polluted that is east of the Mississippi River.

Year-Round Particle Pollution

This year saw mixed results in terms of annual particle levels among the 26 most polluted cities in the United States: 13 of these cities saw increased particle levels; 11 cities improved; one was not included in last year's report; and one maintained the same levels as last year's report. Nine cities among the most polluted achieved their lowest ever annual particle levels. (The list of most polluted cities for annual particle pollution contains 26 cities instead of 25 due to a tie for 25th place.)

More people live in areas with unhealthy year-round particle pollution than in last year's report. More than 21.2 million people live in 19 counties where the annual average concentration of particle pollution was too high. This is higher than the 20.5 million Americans living in 18 counties in the 2019 report.

Bakersfield, CA returned to the rank of most polluted city for year-round particle pollution in 2016-2018. As with the short-term particle category, Bakersfield and Fresno also swapped rankings for annual particle pollution levels. Bakersfield returns to #1 most polluted in the nation while Fresno ranks #2, having tied its lowest annual average.

Thirteen of the 26 cities most polluted year-round by particle pollution saw increases over levels in the 2019 report: Bakersfield, CA; Visalia, CA; San Jose-San Francisco-Oakland, CA; Phoenix, AZ; El Centro, CA; Detroit-Warren-Ann Arbor, MI; McAllen-Edinburgh, TX; Philadelphia-Reading-Camden, PA-NJ-DE-MD; Sacramento-Roseville, CA; Shreveport-Bossier City-Minden, LA; Medford-Grants Pass, OR; Chico, CA and St. Louis-St. Charles-Farmington, MO-IL.

Eleven of the 26 most polluted cities had lower year-round particle levels, of which nine matched (Pittsburgh and Fresno) or newly achieved (Atlanta, Birmingham, Chicago, Cincinnati, Cleveland, Houston, and Indianapolis) their lowest respective averages ever.

Of the remaining two cities among the most polluted in the nation by annual particles, Los Angeles, CA, had the same level as last year, while Brownsville, TX, did not have annual particle pollution data available last year for comparison.

More cities among the most polluted by annual particle levels saw increases than improved in the 2020 report.

Nine cities among the most polluted for annual particle pollution fail to meet the current national air quality standards. However, evidence shows that no threshold exists for harmful effects from particle pollution—that is, that even levels lower than the official standard are not safe to breathe.

Overall, cities in the western U.S. dominate the list, with 15 cities among the 26 most polluted by annual particles. California continues to claim more places on the list than any other state, with six of the ten most polluted, including each of the worst five—and six of the nine cities that fail to achieve the national standard. Fairbanks, Phoenix, Pittsburgh and Detroit are also among the ten most polluted, with only Detroit achieving the national standard. Beyond cities in western states, the remainder of the most particle-polluted cities all meet the standard and are distributed throughout the Midwest, Southeast and Mid-Atlantic regions.

Cities with high power plant emissions as well as local, industrial sources continue to show up on the list, including Pittsburgh; Detroit; Cleveland; Philadelphia; Cincinnati; Birmingham, AL; Indianapolis; Shreveport, LA; and Atlanta.

Fortunately, year-round particle pollution continues to decline across most of the nation, unlike the days with high ozone and high short-term particle pollution.

Because of their high numbers and long duration, western wildfires contributed to some of the elevated annual averages in Western cities. That is especially true in California and Pacific Northwest communities that experienced major wildfire smoke impacts in 2018.

Cleanest Cities

Four cities rank on all three cleanest cities lists for ozone, year-round particle pollution and short-term particle pollution. They had zero high ozone or high particle pollution days and are among the 25 cities with the lowest year-round particle levels. All four repeat their ranking on this list. Listed alphabetically, these cities are:

- Bangor, ME
- Burlington-South Burlington, VT
- Urban Honolulu, HI
- Wilmington, NC

Nine other cities rank among the cleanest cities for both year-round and short-term levels of particle pollution. That means they had no days in the unhealthy level for short-term particle pollution and are on the list of the cleanest cities for year-round particle pollution. Listed alphabetically below, they are:

- Appleton-Oshkosh-Neenah, WI
- Elmira-Corning, NY
- Gainesville-Lake City, FL
- Grand Island, NE
- Palm Bay-Melbourne-Titusville, FL
- Sioux Falls, SD
- Springfield, MA
- St. George, UT
- Syracuse-Auburn, NY

Seventeen other cities rank among the cleanest for ozone and short-term particle pollution. That means they had no days in the unhealthy level for ozone or for short-term particle pollution. Listed alphabetically below, they are:

- Bowling Green-Glasgow, KY
- Clarksville, TN-KY
- Corpus Christi-Kingsville-Alice, TX
- Fayetteville-Sanford-Lumberton, NC
- Fayetteville-Springdale-Rogers, AR
- Florence, SC
- Fort Smith, AR-OK
- Gadsden, AL
- Houma-Thibodaux, LA
- La Crosse-Onalaska, WI-MN
- Lincoln-Beatrice, NE
- Monroe-Ruston, LA
- Morgantown-Fairmont, WV
- Roanoke, VA
- Springfield, MO
- Tallahassee, FL
- Topeka, KS

Five cities rank on both lists for ozone and year-round particle pollution levels. These cities had no days in the unhealthy level for ozone pollution and are on the list of the cleanest cities for year-round particle pollution. Listed alphabetically below, they are:

- Anchorage, AK
- Bismarck, ND
- Casper, WY
- Duluth, MN-WI
- Salinas, CA

People at Risk

The "State of the Air" 2020 shows that too many people in the United States live where the air is unhealthy for them to breathe.

- **Nearly five in 10 people (45.8 percent) in the United States live in counties with unhealthful levels of either ozone or particle pollution.** Approximately 150 million Americans live in these 257 counties with unhealthful levels of either ozone or short-term or year-round particles.
  - **The number has increased—again.** This year's report found 8.76 million more Americans living in counties with unhealthy air compared to last year's report, and 15.9 million more Americans compared to the 2018 report. Fortunately, the total is still far below the 166 million in the years covered in the 2016 report (2012-2014).
  - **Why? One big reason is climate change.** Warmer weather, different rain patterns and major wildfires all contribute to continued challenges to long-term progress in reducing harmful air pollution under the Clean Air Act.
- **More than four in 10 (41.9 percent) of the people in the United States live in areas with unhealthy levels of ozone pollution.** More than 137 million people live in the 205 counties that earned an F for ozone in this year's report, approximately 3 million more people than in last year's report.
- **Nearly one in six people (16.3 percent) in the United States—more than 53.3 million—live in an area with too many days with unhealthful levels of particle pollution.** More people experienced those unhealthy spikes than in the last three reports. In the 2019 report, approximately 49.6 million people experienced too many unhealthy days; in the 2018 report, approximately 35.1 million people; and in the 2017 report, approximately 43 million people.

- **More than 21.2 million people (6.5 percent) suffered from unhealthy year-round levels of particle pollution in 2016-2018.** These people live in 19 counties where the annual average concentration of particle pollution was too high. This population estimate is higher than the 20.5 million Americans living in 18 counties with unhealthy levels of year-round particle pollution reported in the 2019 report that covered 2015-2017.
- **20.8 million people (6.4 percent) live in 14 counties with unhealthful levels of all three: ozone and short-term and year-round particle pollution in 2016-2018.** This is over 600,000 more people living in the 12 U.S. counties with unhealthy levels for all three measures than in the 2019 report that covered 2015-2017.

Many people are at greater risk because of their age; because they have asthma or other chronic lung disease or cardiovascular disease; because they have ever smoked; because they belong to communities of color or because they have low socioeconomic status. With the risks from airborne pollution being so great, the Lung Association seeks to inform people who may be in danger. The following list identifies the numbers of people in each at-risk group.

- **Older and Younger**—Nearly 22 million adults age 65 and over and 34.2 million children under age 18 live in counties that received an F for at least one pollutant. More than 2.8 million seniors and 5 million children live in counties failing all three tests.
- **Asthma**—2.5 million children and 10.6 million adults with asthma live in counties that received an F for at least one pollutant. More than 316,000 children and nearly 1.4 million adults with asthma live in counties failing all three tests.
- **Chronic Obstructive Pulmonary Disease (COPD)**—Nearly 7 million people with COPD live in counties that received an F for at least one pollutant. More than 750,000 people with COPD live in counties failing all three tests.
- **Lung Cancer**—More than 77,000 people were diagnosed with lung cancer and live in counties that received an F for at least one pollutant. Nearly 8,400 people were diagnosed with lung cancer and live in counties failing all three tests.
- **Cardiovascular Disease**—More than 9.3 million people with cardiovascular diseases live in counties that received an F for at least one pollutant. Over 1 million people live in counties failing all three tests.
- **Poverty**—Evidence shows that people who have low incomes may face higher risk from air pollution. More than 18.7 million people with incomes meeting the federal poverty definition live in counties that received an F for at least one pollutant. More than 3 million people in poverty live in counties failing all three tests.
- **Communities of Color**—Studies have found that Hispanics, Asians, American Indians/Alaska Natives and especially African Americans experienced higher risks of harm, including premature death, from exposure to air pollution. Approximately 74 million people of color live in counties that received at least one failing grade for ozone and/or particle pollution. Over 14 million people of color live in counties that received failing grades on all three measures.
- **People Who Have Ever Smoked**—There is some recent evidence suggesting that people who have a history of smoking are at greater risk of premature death and of lung cancer when subjected to long-term exposure to fine particle pollution. Over 14.3 million Americans who have ever smoked live in counties that received at least one F for particle pollution. Of those, some 5.5 million people live in counties that received failing grades for all three pollutants.

People at Risk In 25 U.S. Cities Most Polluted by Short-Term Particle Pollution (24-hour $PM_{2.5}$)

2020 Rank[1]	Metropolitan Statistical Areas	Total Population[2]	Under 18[3]	65 and Over[3]	Pediatric Asthma[4,6]	Adult Asthma[5,6]	COPD[7]	Lung Cancer[8]	CV Disease[9]	Ever Smoked[10]	People of Color[11]	Poverty[12]
1	Fresno-Madera-Hanford, CA	1,303,438	366,122	159,680	22,603	79,423	41,465	505	59,329	307,787	913,514	264,309
2	Bakersfield, CA	896,764	259,180	98,347	16,001	53,894	27,503	348	39,003	208,055	596,328	177,021
3	San Jose-San Francisco-Oakland, CA	9,666,055	2,083,848	1,441,150	128,651	647,292	353,447	3,744	513,313	2,532,824	5,940,594	910,851
4	Fairbanks, AK	98,971	23,861	10,204	1,708	6,791	4,061	55	4,617	31,974	30,429	8,104
5	Yakima, WA	251,446	74,480	34,524	5,444	16,911	8,764	135	13,490	66,527	144,155	40,961
6	Los Angeles-Long Beach, CA	18,764,814	4,270,638	2,583,214	263,657	1,234,623	662,425	7,264	956,017	4,815,313	13,006,958	2,440,945
7	Missoula, MT	118,791	22,315	18,506	1,189	9,790	5,034	62	7,707	41,975	12,853	14,719
7	Redding-Red Bluff, CA	243,956	53,947	49,942	3,331	16,467	9,990	94	15,013	65,808	57,523	37,668
7	Salt Lake City-Provo-Orem, UT	2,606,548	775,252	263,814	42,545	170,894	75,292	664	104,041	457,968	603,254	217,929
10	Phoenix-Mesa, AZ	4,911,851	1,164,393	775,920	93,868	379,311	261,519	2,194	337,858	1,505,840	2,203,881	600,386
11	Sacramento-Roseville, CA	2,619,754	599,091	414,668	36,986	173,009	96,594	1,013	141,372	679,845	1,234,160	338,884
12	Visalia, CA	465,861	142,848	53,292	8,819	27,348	14,170	181	20,216	105,845	335,036	102,451
13	Logan, UT-ID	140,794	42,891	13,952	2,427	8,983	3,916	39	5,308	25,208	22,401	17,024
14	Spokane-Spokane Valley-Coeur d'Alene, WA-ID	721,396	160,636	124,491	11,686	52,584	30,239	379	46,302	215,142	102,458	87,827
14	Seattle-Tacoma, WA	4,853,364	1,036,349	704,616	75,755	365,436	187,900	2,611	286,299	1,434,277	1,687,561	424,549
16	Pittsburgh-New Castle-Weirton, PA-OH-WV	2,612,492	493,652	526,956	47,773	214,077	160,936	1,678	219,828	920,378	363,815	291,201
17	Chico, CA	231,256	46,213	42,992	2,853	15,844	9,018	90	13,309	62,372	65,598	42,016
18	Medford-Grants Pass, OR	306,957	62,363	70,945	4,521	28,323	18,493	155	26,297	108,610	54,567	46,792
19	Salinas, CA	435,594	113,834	59,201	7,028	27,378	14,688	169	21,215	106,690	306,813	55,614
20	El Centro, CA	181,827	51,765	23,580	3,196	11,043	5,862	71	8,440	42,925	162,999	37,014
21	Santa Maria-Santa Barbara, CA	446,527	98,787	68,465	6,099	29,547	15,916	173	23,056	115,063	249,761	54,029
22	Eugene-Springfield, OR	379,611	69,868	73,392	5,065	36,150	21,366	192	29,676	133,980	70,215	67,217
23	Reno-Carson City-Fernley, NV	629,453	132,368	114,311	9,214	39,394	37,442	319	47,976	208,837	216,972	63,145
24	Portland-Vancouver-Salem, OR-WA	3,239,335	704,918	498,715	51,192	288,636	159,742	1,659	222,293	1,060,542	870,251	340,971
25	Las Vegas-Henderson, NV	2,276,993	525,247	342,326	36,562	139,723	124,078	1,152	156,491	722,232	1,300,943	314,702

Notes:

1. Cities are ranked using the highest weighted average for any county within that Combined Metropolitan Statistical Area or Metropolitan Statistical Area.
2. **Total population** represents the at-risk populations for all counties within the respective Combined Metropolitan Statistical Area or Metropolitan Statistical Area.
3. Those **under 18** and **65 and over** are vulnerable to $PM_{2.5}$ and are, therefore, included. They should not be used as population denominators for disease estimates.
4. **Pediatric asthma** estimates are for those under 18 years of age and represent the **estimated** number of people who had asthma in 2018 based on state rates (BRFSS) applied to population estimates (U.S. Census).
5. **Adult asthma** estimates are for those 18 years and older and represent the **estimated** number of people who had asthma in 2018 based on state rates (BRFSS) applied to population estimates (U.S. Census).
6. Adding across rows does not produce valid estimates. Adding the disease categories (asthma, COPD, etc.) will double-count people who have been diagnosed with more than one disease.
7. **COPD** estimates are for adults 18 and over who have been diagnosed within their lifetime, based on state rates (BRFSS) applied to population estimates (U.S. Census).
8. **Lung cancer** estimates are the number of new cases diagnosed in 2016.
9. **CV disease** is cardiovascular disease and estimates are for adults 18 and over who have been diagnosed within their lifetime, based on state rates (BRFSS) applied to population estimates (U.S. Census).
10. **Ever smoked** estimates are for adults 18 and over who have ever smoked 100 or more cigarettes in their life, based on state rates (BRFSS) applied to population estimates (U.S. Census).
11. **People of color** are anyone of Hispanic ethnicity or a race other than white.
12. **Poverty** estimates come from the U.S. Census Bureau and are for all ages.

People at Risk In 25 U.S. Cities Most Polluted by Year-Round Particle Pollution (Annual $PM_{2.5}$)

2020 Rank[1]	Metropolitan Statistical Areas	Total Population[2]	Under 18[3]	65 and Over[3]	Pediatric Asthma[4,6]	Adult Asthma[5,6]	COPD[7]	Lung Cancer[8]	CV Disease[9]	Ever Smoked[10]	People of Color[11]	Poverty[12]
1	Bakersfield, CA	896,764	259,180	98,347	16,001	53,894	27,503	348	39,003	208,055	596,328	177,021
2	Fresno-Madera-Hanford, CA	1,303,438	366,122	159,680	22,603	79,423	41,465	505	59,329	307,787	913,514	264,309
3	Visalia, CA	465,861	142,848	53,292	8,819	27,348	14,170	181	20,216	105,845	335,036	102,451
4	Los Angeles-Long Beach, CA	18,764,814	4,270,638	2,583,214	263,657	1,234,623	662,425	7,264	956,017	4,815,313	13,006,958	2,440,945
5	San Jose-San Francisco-Oakland, CA	9,666,055	2,083,848	1,441,150	128,651	647,292	353,447	3,744	513,313	2,532,824	5,940,594	910,851
6	Fairbanks, AK	98,971	23,861	10,204	1,708	6,791	4,061	55	4,617	31,974	30,429	8,104
7	Phoenix-Mesa, AZ	4,911,851	1,164,393	775,920	93,868	379,311	261,519	2,194	337,858	1,505,840	2,203,881	600,386
8	El Centro, CA	181,827	51,765	23,580	3,196	11,043	5,862	71	8,440	42,925	162,999	37,014
8	Pittsburgh-New Castle-Weirton, PA-OH-WV	2,612,492	493,652	526,956	47,773	214,077	160,936	1,678	219,828	920,378	363,815	291,201
10	Detroit-Warren-Ann Arbor, MI	5,353,002	1,167,571	878,042	100,227	467,545	361,975	3,258	405,383	1,903,919	1,711,850	766,528
11	Cleveland-Akron-Canton, OH	3,599,264	762,709	665,627	59,285	266,809	248,192	2,369	303,425	1,308,507	862,428	482,828
12	McAllen-Edinburg, TX	930,464	303,179	103,338	23,991	46,626	37,355	460	54,456	221,989	875,994	278,136
12	Philadelphia-Reading-Camden, PA-NJ-DE-MD	7,204,035	1,563,815	1,172,273	137,782	546,942	367,327	4,448	505,159	2,313,363	2,755,807	863,095
14	Birmingham-Hoover-Talladega, AL	1,315,071	299,130	216,148	39,477	107,332	104,605	863	131,219	445,278	458,703	188,402
14	Cincinnati-Wilmington-Maysville, OH-KY-IN	2,272,152	531,476	347,135	39,399	171,496	158,664	1,608	181,756	812,130	462,928	262,757
16	Indianapolis-Carmel-Muncie, IN	2,431,361	587,696	347,061	51,145	182,624	164,004	1,743	195,671	830,603	618,582	297,292
16	Missoula, MT	118,791	22,315	18,506	1,189	9,790	5,034	62	7,707	41,975	12,853	14,719
16	Sacramento-Roseville, CA	2,619,754	599,091	414,668	36,986	173,009	96,594	1,013	141,372	679,845	1,234,160	338,884
16	Shreveport-Bossier City-Minden, LA	436,341	104,477	72,410	9,142	29,706	33,398	282	39,553	144,433	203,797	85,607
20	Chicago-Naperville, IL-IN-WI	9,866,910	2,241,630	1,451,741	140,534	673,886	510,490	6,298	633,418	2,960,335	4,578,321	1,110,613
20	Medford-Grants Pass, OR	306,957	62,363	70,945	4,521	28,323	18,493	155	26,297	108,610	54,567	46,792
22	Houston-The Woodlands, TX	7,183,143	1,897,159	809,495	150,125	395,360	317,983	3,559	462,780	1,889,107	4,591,549	1,018,964
23	Atlanta-Athens-Clarke County-Sandy Springs, GA-AL	6,775,511	1,642,659	855,689	124,911	461,612	374,851	4,240	461,776	1,931,461	3,450,999	803,621
23	Chico, CA	231,256	46,213	42,992	2,853	15,844	9,018	90	13,309	62,372	65,598	42,016
25	Brownsville-Harlingen-Raymondville, TX	445,423	133,641	60,430	10,575	23,290	19,934	220	29,290	112,466	406,442	123,562
25	St. Louis-St. Charles-Farmington, MO-IL	2,909,777	643,945	483,131	50,287	208,874	193,154	1,965	220,425	969,825	748,141	337,275

Notes:

1. Cities are ranked using the highest weighted average for any county within that Combined Metropolitan Statistical Area or Metropolitan Statistical Area.
2. **Total population** represents the at-risk populations for all counties within the respective Combined Metropolitan Statistical Area or Metropolitan Statistical Area.
3. Those **under 18** and **65 and over** are vulnerable to $PM_{2.5}$ and are, therefore, included. They should not be used as population denominators for disease estimates.
4. **Pediatric asthma** estimates are for those under 18 years of age and represent the **estimated** number of people who had asthma in 2018 based on state rates (BRFSS) applied to population estimates (U.S. Census).
5. **Adult asthma** estimates are for those 18 years and older and represent the **estimated** number of people who had asthma in 2018 based on state rates (BRFSS) applied to population estimates (U.S. Census).
6. Adding across rows does not produce valid estimates. Adding the disease categories (asthma, COPD, etc.) will double-count people who have been diagnosed with more than one disease.
7. **COPD** estimates are for adults 18 and over who have been diagnosed within their lifetime, based on state rates (BRFSS) applied to population estimates (U.S. Census).
8. **Lung cancer** estimates are the number of new cases diagnosed in 2016.
8. **CV disease** is cardiovascular disease and estimates are for adults 18 and over who have been diagnosed within their lifetime, based on state rates (BRFSS) applied to population estimates (U.S. Census).
9. **Ever smoked** estimates are for adults 18 and over who have ever smoked 100 or more cigarettes in their life, based on state rates (BRFSS) applied to population estimates (U.S. Census).
10. **People of color** are anyone of Hispanic ethnicity or a race other than white.
11. **Poverty** estimates come from the U.S. Census Bureau and are for all ages.

People at Risk In 25 Most Ozone-Polluted Cities

2020 Rank[1]	Metropolitan Statistical Areas	Total Population[2]	Under 18[3]	65 and Over[3]	Pediatric Asthma[4,6]	Adult Asthma[5,6]	COPD[7]	CV Disease[8]	People of Color[9]	Poverty[10]
1	Los Angeles-Long Beach, CA	18,764,814	4,270,638	2,583,214	263,657	1,234,623	662,425	956,017	13,006,958	2,440,945
2	Visalia, CA	465,861	142,848	53,292	8,819	27,348	14,170	20,216	335,036	102,451
3	Bakersfield, CA	896,764	259,180	98,347	16,001	53,894	27,503	39,003	596,328	177,021
4	Fresno-Madera-Hanford, CA	1,303,438	366,122	159,680	22,603	79,423	41,465	59,329	913,514	264,309
5	Sacramento-Roseville, CA	2,619,754	599,091	414,668	36,986	173,009	96,594	141,372	1,234,160	338,884
6	San Diego-Chula Vista-Carlsbad, CA	3,343,364	722,408	469,454	44,599	222,727	118,450	170,564	1,832,022	372,148
7	Phoenix-Mesa, AZ	4,911,851	1,164,393	775,920	93,868	379,311	261,519	337,858	2,203,881	600,386
8	San Jose-San Francisco-Oakland, CA	9,666,055	2,083,848	1,441,150	128,651	647,292	353,447	513,313	5,940,594	910,851
9	Las Vegas-Henderson, NV	2,276,993	525,247	342,326	36,562	139,723	124,078	156,491	1,300,943	314,702
10	Denver-Aurora, CO	3,572,798	803,973	464,674	57,540	250,127	117,348	156,017	1,239,843	300,335
11	Salt Lake City-Provo-Orem, UT	2,606,548	775,252	263,814	42,545	170,894	75,292	104,041	603,254	217,929
12	New York-Newark, NY-NJ-CT-PA	22,679,948	4,852,039	3,601,621	332,013	1,727,257	999,220	1,399,513	11,714,237	2,699,912
13	Redding-Red Bluff, CA	243,956	53,947	49,942	3,331	16,467	9,990	15,013	57,523	37,668
14	Houston-The Woodlands, TX	7,183,143	1,897,159	809,495	150,125	395,360	317,983	462,780	4,591,549	1,018,964
15	El Centro, CA	181,827	51,765	23,580	3,196	11,043	5,862	8,440	162,999	37,014
16	Chicago-Naperville, IL-IN-WI	9,866,910	2,241,630	1,451,741	140,534	673,886	510,490	633,418	4,578,321	1,110,613
17	El Paso-Las Cruces, TX-NM	1,063,075	282,247	138,167	22,128	61,919	47,098	67,360	905,812	222,872
18	Chico, CA	231,256	46,213	42,992	2,853	15,844	9,018	13,309	65,598	42,016
19	Fort Collins, CO	350,518	68,703	54,938	4,917	25,460	12,323	16,693	61,373	36,054
20	Washington-Baltimore-Arlington, DC-MD-VA-WV-PA	9,796,147	2,213,754	1,378,591	170,198	715,068	458,462	617,799	4,798,740	829,272
21	Dallas-Fort Worth, TX-OK	7,948,477	2,051,630	931,511	162,557	442,787	361,074	526,069	4,201,204	896,752
22	Sheboygan, WI	115,456	25,431	20,789	2,146	8,211	4,980	7,138	18,681	8,432
23	Philadelphia-Reading-Camden, PA-NJ-DE-MD	7,204,035	1,563,815	1,172,273	137,782	546,942	367,327	505,159	2,755,807	863,095
24	Milwaukee-Racine-Waukesha, WI	2,049,391	464,985	326,928	39,235	145,433	83,225	116,927	619,356	255,115
25	Hartford-East Hartford, CT	1,473,084	293,974	258,397	28,550	121,927	63,740	89,946	467,678	143,411

Notes:

1. Cities are ranked using the highest weighted average for any county within that Combined Metropolitan Statistical Area or Metropolitan Statistical Area.
2. **Total population** represents the at-risk populations for all counties within the respective Combined Metropolitan Statistical Area or Metropolitan Statistical Area.
3. Those **under 18** and **65 and over** are vulnerable to ozone and are, therefore, included. They should not be used as population denominators for disease estimates.
4. **Pediatric asthma** estimates are for those under 18 years of age and represent the **estimated** number of people who had asthma in 2018 based on state rates (BRFSS) applied to population estimates (U.S. Census).
5. **Adult asthma** estimates are for those 18 years and older and represent the **estimated** number of people who had asthma in 2018 based on state rates (BRFSS) applied to population estimates (U.S. Census).
6. Adding across rows does not produce valid estimates. Adding the disease categories (asthma, COPD, etc.) will double-count people who have been diagnosed with more than one disease.
7. **COPD** estimates are for adults 18 and over who have been diagnosed within their lifetime, based on state rates (BRFSS) applied to population estimates (U.S. Census).
8. **CV disease** is cardiovascular disease and estimates are for adults 18 and over who have been diagnosed within their lifetime, based on state rates (BRFSS) applied to population estimates (U.S. Census).
9. **People of color** are anyone of Hispanic ethnicity or a race other than white.
10. **Poverty** estimates come from the U.S. Census Bureau and are for all ages.

People at Risk in 25 Counties Most Polluted by Short-Term Particle Pollution (24-hour $PM_{2.5}$)

				At-Risk Groups										High $PM_{2.5}$ Days in Unhealthy Ranges, 2016–2018	
2020 Rank[1]	County	State	Total Population[2]	Under 18[3]	65 and Over[3]	Pediatric Asthma[4,6]	Adult Asthma[5,6]	COPD[7]	Lung Cancer[8]	CV Disease[9]	Ever Smoked[10]	People of Color[11]	Poverty[12]	Weighted Avg.[13]	Grade[14]
1	Fresno	CA	994,400	281,819	122,113	17,399	60,395	31,587	385	45,226	234,129	705,643	208,627	37.8	F
2	Kings	CA	151,366	40,964	15,516	2,529	9,283	4,580	59	6,416	35,590	103,277	25,481	36.2	F
3	Kern	CA	896,764	259,180	98,347	16,001	53,894	27,503	348	39,003	208,055	596,328	177,021	35.8	F
4	Stanislaus	CA	549,815	148,801	72,319	9,187	34,134	18,290	213	26,395	133,042	323,635	84,744	26.7	F
5	Fairbanks North Star Borough	AK	98,971	23,861	10,204	1,708	6,791	4,061	55	4,617	31,974	30,429	8,104	26.5	F
6	San Joaquin	CA	752,660	204,316	95,916	12,614	46,649	24,840	292	35,760	181,645	519,021	105,351	21.5	F
7	Ravalli	MT	43,172	8,246	11,138	439	3,398	2,415	23	3,745	15,880	3,154	6,628	19.8	F
8	Merced	CA	274,765	80,588	30,845	4,975	16,418	8,420	107	11,965	63,423	200,196	56,863	19.7	F
9	Yakima	WA	251,446	74,480	34,524	5,444	16,911	8,764	135	13,490	66,527	144,155	40,961	17.8	F
9	Lewis and Clark	MT	68,700	14,770	12,903	787	5,395	3,278	36	4,971	24,014	6,059	7,061	17.8	F
11	Madera	CA	157,672	43,339	22,051	2,676	9,745	5,298	61	7,688	38,068	104,594	30,201	17.2	F
11	Siskiyou	CA	43,724	8,802	11,160	543	3,062	1,998	17	3,066	12,428	10,636	7,396	17.2	F
13	Plumas	CA	18,804	3,173	5,345	196	1,378	927	7	1,435	5,635	3,123	2,317	16.2	F
14	Okanogan	WA	42,132	9,769	9,094	714	3,150	1,916	23	3,087	12,841	14,878	7,049	14.8	F
15	Lincoln	MT	19,794	3,609	5,670	192	1,557	1,182	10	1,840	7,431	1,491	3,964	14.3	F
16	Los Angeles	CA	10,105,518	2,188,893	1,375,957	135,136	673,459	358,245	3,911	515,500	2,622,021	7,466,160	1,409,155	13.8	F
17	Shoshone	ID	12,796	2,630	2,923	188	866	662	6	988	4,079	1,140	2,371	13.3	F
18	Missoula	MT	118,791	22,315	18,506	1,189	9,790	5,034	62	7,707	41,975	12,853	14,719	12.3	F
18	Utah	UT	622,213	207,710	48,050	11,399	38,230	15,362	159	20,064	100,766	111,686	57,136	12.3	F
18	Tehama	CA	63,916	15,363	12,389	948	4,205	2,533	25	3,797	16,786	20,718	10,749	12.3	F
21	Colusa	CA	21,627	5,907	3,163	365	1,344	745	8	1,087	5,273	14,202	2,350	12.0	F
22	Pinal	AZ	447,138	100,778	91,129	8,124	34,832	26,058	201	34,552	142,549	194,203	54,399	11.5	F
22	Salt Lake	UT	1,152,633	312,889	125,157	17,171	78,549	35,187	294	49,059	211,172	338,240	102,660	11.5	F
24	Sacramento	CA	1,540,975	363,909	217,601	22,467	100,345	54,282	596	78,584	391,898	859,537	217,138	11.3	F
24	Mendocino	CA	87,606	18,713	19,366	1,155	5,988	3,712	34	5,617	24,035	30,951	15,140	11.3	F

Notes:

1. Counties are ranked by weighted average. See note 13 below.
2. **Total population** represents the at-risk populations in counties with $PM_{2.5}$ monitors.
3. Those **under 18** and **65 and over** are vulnerable to $PM_{2.5}$ and are, therefore, included. They should not be used as population denominators for disease estimates.
4. **Pediatric asthma** estimates are for those under 18 years of age and represent the **estimated** number of people who had asthma in 2018 based on state rates (BRFSS) applied to population estimates (U.S. Census).
5. Adult asthma estimates are for those 18 years and older and represent the **estimated** number of people who had asthma in 2018 based on state rates (BRFSS) applied to population estimates (U.S. Census).
6. Adding across rows does not produce valid estimates. Adding the disease categories (asthma, COPD, etc.) will double-count people who have been diagnosed with more than one disease.
7. **COPD** estimates are for adults 18 and over who have been diagnosed within their lifetime, based on state rates (BRFSS) applied to population estimates (U.S. Census).
8. **Lung cancer** estimates are the number of new cases diagnosed in 2016.
9. **CV disease** is cardiovascular disease and estimates are for adults 18 and over who have been diagnosed within their lifetime, based on state rates (BRFSS) applied to population estimates (U.S. Census).
10. **Ever smoked** estimates are for adults 18 and over who have ever smoked 100 or more cigarettes in their life, based on state rates (BRFSS) applied to population estimates (U.S. Census).
11. **People of color** are anyone of Hispanic ethnicity or a race other than white.
12. **Poverty** estimates come from the U.S. Census Bureau and are for all ages.
13. The **weighted average** was derived by counting the number of days in each unhealthful range (orange, red, purple, maroon) in each year (2016-2018), multiplying the total in each range by the assigned standard weights (i.e., 1 for orange, 1.5 for red, 2.0 for purple, 2.5 for maroon), and calculating the average.
14. **Grade** is assigned by weighted average as follows: A=0.0, B=0.3-0.9, C=1.0-2.0, D=2.1-3.2, F=3.3+.

People at Risk in 25 Counties Most Polluted by Year-Round Particle Pollution (Annual $PM_{2.5}$)

				At-Risk Groups										$PM_{2.5}$ Annual, 2016–2018	
2020 Rank[1]	County	State	Total Population[2]	Under 18[3]	65 and Over[3]	Pediatric Asthma[4,6]	Adult Asthma[5,6]	COPD[7]	Lung Cancer[8]	CV Disease[9]	Ever Smoked[10]	People of Color[11]	Poverty[12]	Design Value[13]	Pass/ Fail[14]
1	Kern	CA	896,764	259,180	98,347	16,001	53,894	27,503	348	39,003	208,055	596,328	177,021	17.8	Fail
2	Kings	CA	151,366	40,964	15,516	2,529	9,283	4,580	59	6,416	35,590	103,277	25,481	16.8	Fail
3	Tulare	CA	465,861	142,848	53,292	8,819	27,348	14,170	181	20,216	105,845	335,036	102,451	16.1	Fail
4	Fresno	CA	994,400	281,819	122,113	17,399	60,395	31,587	385	45,226	234,129	705,643	208,627	15.0	Fail
5	Plumas	CA	18,804	3,173	5,345	196	1,378	927	7	1,435	5,635	3,123	2,317	14.7	Fail
5	San Bernardino	CA	2,171,603	572,278	251,361	35,331	135,544	70,099	841	99,838	524,916	1,564,843	317,514	14.7	Fail
7	Stanislaus	CA	549,815	148,801	72,319	9,187	34,134	18,290	213	26,395	133,042	323,635	84,744	14.2	Fail
8	Riverside	CA	2,450,758	616,126	353,122	38,038	156,550	85,478	949	124,180	612,354	1,600,121	307,511	13.9	Fail
9	San Joaquin	CA	752,660	204,316	95,916	12,614	46,649	24,840	292	35,760	181,645	519,021	105,351	13.8	Fail
10	Merced	CA	274,765	80,588	30,845	4,975	16,418	8,420	107	11,965	63,423	200,196	56,863	13.4	Fail
11	Fairbanks North Star Borough	AK	98,971	23,861	10,204	1,708	6,791	4,061	55	4,617	31,974	30,429	8,104	13.1	Fail
12	Pinal	AZ	447,138	100,778	91,129	8,124	34,832	26,058	201	34,552	142,549	194,203	54,399	13.0	Fail
13	Lincoln	MT	19,794	3,609	5,670	192	1,557	1,182	10	1,840	7,431	1,491	3,964	12.9	Fail
14	Madera	CA	157,672	43,339	22,051	2,676	9,745	5,298	61	7,688	38,068	104,594	30,201	12.8	Fail
15	Los Angeles	CA	10,105,518	2,188,893	1,375,957	135,136	673,459	358,245	3,911	515,500	2,622,021	7,466,160	1,409,155	12.7	Fail
16	Allegheny	PA	1,218,452	227,749	230,377	22,168	99,742	70,310	778	96,971	424,109	263,512	138,397	12.6	Fail
16	Imperial	CA	181,827	51,765	23,580	3,196	11,043	5,862	71	8,440	42,925	162,999	37,014	12.6	Fail
18	Klamath	OR	67,653	14,706	14,340	1,066	6,153	3,903	34	5,512	23,338	15,294	12,310	12.4	Fail
19	Hawaii	HI	200,983	43,553	42,032	4,444	14,524	6,922	92	13,054	62,784	140,018	30,903	12.3	Fail
20	Alameda	CA	1,666,753	342,510	230,510	21,146	112,623	59,859	645	86,118	438,363	1,148,783	147,394	12.0	Pass
21	Lemhi	ID	7,961	1,488	2,409	106	544	458	4	726	2,679	533	1,154	11.4	Pass
22	Wayne	MI	1,753,893	414,221	270,554	35,558	150,021	113,859	1,066	126,753	607,144	886,177	376,649	11.3	Pass
23	Shoshone	ID	12,796	2,630	2,923	188	866	662	6	988	4,079	1,140	2,371	11.2	Pass
24	Ventura	CA	850,967	194,553	132,387	12,011	56,290	31,535	329	46,171	221,522	468,345	76,206	11.0	Pass
24	Cuyahoga	OH	1,243,857	257,882	225,983	20,045	92,829	84,905	817	103,312	453,134	512,719	217,166	11.0	Pass

Notes:

1. Counties are ranked by design value. See note 13 below.
2. **Total population** represents the at-risk populations in counties with $PM_{2.5}$ monitors.
3. Those **under 18** and **65 and over** are vulnerable to $PM_{2.5}$ and are, therefore, included. They should not be used as population denominators for disease estimates.
4. **Pediatric asthma** estimates are for those under 18 years of age and represent the **estimated** number of people who had asthma in 2018 based on state rates (BRFSS) applied to population estimates (U.S. Census).
5. **Adult asthma** estimates are for those 18 years and older and represent the **estimated** number of people who had asthma in 2018 based on state rates (BRFSS) applied to population estimates (U.S. Census).
6. Adding across rows does not produce valid estimates. Adding the disease categories (asthma, COPD, etc.) will double-count people who have been diagnosed with more than one disease.
7. **COPD** estimates are for adults 18 and over who have been diagnosed within their lifetime, based on state rates (BRFSS) applied to population estimates (U.S. Census).
8. **Lung cancer** estimates are the number of new cases diagnosed in 2016.
9. **CV disease** is cardiovascular disease and estimates are for adults 18 and over who have been diagnosed within their lifetime, based on state rates (BRFSS) applied to population estimates (U.S. Census).
10. **Ever smoked** estimates are for adults 18 and over who have ever smoked 100 or more cigarettes in their life, based on state rates (BRFSS) applied to population estimates (U.S. Census).
11. **People of color** are anyone of Hispanic ethnicity or a race other than white.
12. **Poverty** estimates come from the U.S. Census Bureau and are for all ages.
13. The **design value** is the calculated concentration of a pollutant based on the form of the Annual $PM_{2.5}$ National Ambient Air Quality Standard, and is used by EPA to determine whether the air quality in a county meets the current (2012) standard (U.S. EPA).
14. **Grades** are based on EPA's determination of meeting or failure to meet the NAAQS for annual $PM_{2.5}$ levels during 2015-2017. Counties meeting the NAAQS received grades of Pass; counties not meeting the NAAQS received grades of Fail.

People at Risk in 25 Most Ozone-Polluted Counties

				At-Risk Groups								High Ozone Days in Unhealthy Ranges, 2016–2018	
2020 Rank[1]	County	State	Total Population[2]	Under 18[3]	65 and Over[3]	Pediatric Asthma[4,6]	Adult Asthma[5,6]	COPD[7]	CV Disease[8]	People of Color[9]	Poverty[10]	Weighted Avg.[11]	Grade[12]
1	San Bernardino	CA	2,171,603	572,278	251,361	35,331	135,544	70,099	99,838	1,564,843	317,514	174.3	F
2	Riverside	CA	2,450,758	616,126	353,122	38,038	156,550	85,478	124,180	1,600,121	307,511	138.8	F
3	Los Angeles	CA	10,105,518	2,188,893	1,375,957	135,136	673,459	358,245	515,500	7,466,160	1,409,155	111.0	F
4	Tulare	CA	465,861	142,848	53,292	8,819	27,348	14,170	20,216	335,036	102,451	105.2	F
5	Kern	CA	896,764	259,180	98,347	16,001	53,894	27,503	39,003	596,328	177,021	103.2	F
6	Fresno	CA	994,400	281,819	122,113	17,399	60,395	31,587	45,226	705,643	208,627	85.8	F
7	Nevada	CA	99,696	17,071	27,380	1,054	7,266	4,821	7,432	15,030	10,171	51.2	F
8	San Diego	CA	3,343,364	722,408	469,454	44,599	222,727	118,450	170,564	1,832,022	372,148	43.3	F
9	Placer	CA	393,149	87,441	76,906	5,398	26,478	15,911	23,831	109,849	27,596	40.7	F
10	El Dorado	CA	190,678	37,821	40,389	2,335	13,335	8,279	12,506	42,700	15,401	40.2	F
11	Maricopa	AZ	4,410,824	1,052,788	669,285	84,871	340,115	231,647	298,086	1,989,191	535,183	39.8	F
12	Kings	CA	151,366	40,964	15,516	2,529	9,283	4,580	6,416	103,277	25,481	39.5	F
13	Stanislaus	CA	549,815	148,801	72,319	9,187	34,134	18,290	26,395	323,635	84,744	31.8	F
14	Tuolumne	CA	54,539	9,158	14,279	565	3,969	2,562	3,923	11,026	6,417	31.7	F
15	Madera	CA	157,672	43,339	22,051	2,676	9,745	5,298	7,688	104,594	30,201	31.0	F
16	Clark	NV	2,231,647	517,629	328,692	36,032	136,812	120,615	151,858	1,289,911	307,977	30.2	F
17	Jefferson	CO	580,233	114,515	95,477	8,196	41,776	21,576	29,476	127,678	39,799	29.2	F
18	Salt Lake	UT	1,152,633	312,889	125,157	17,171	78,549	35,187	49,059	338,240	102,660	25.7	F
19	Sacramento	CA	1,540,975	363,909	217,601	22,467	100,345	54,282	78,584	859,537	217,138	25.0	F
20	Fairfield	CT	943,823	212,038	149,918	20,593	76,126	39,383	54,861	363,243	92,971	23.0	F
21	Tehama	CA	63,916	15,363	12,389	948	4,205	2,533	3,797	20,718	10,749	22.5	F
21	Mariposa	CA	17,471	2,828	4,882	175	1,289	859	1,325	3,551	2,569	22.5	F
23	Harris	TX	4,698,619	1,251,684	494,264	99,047	257,086	201,143	291,795	3,331,840	767,367	22.3	F
24	Merced	CA	274,765	80,588	30,845	4,975	16,418	8,420	11,965	200,196	56,863	22.0	F
25	Imperial	CA	181,827	51,765	23,580	3,196	11,043	5,862	8,440	162,999	37,014	19.7	F
25	Douglas	CO	342,776	88,978	40,935	6,368	22,775	11,168	14,826	61,999	8,975	19.7	F

Notes:

1. Counties are ranked by weighted average. See note 11 below.
2. **Total population** represents the at-risk populations in counties with $PM_{2.5}$ monitors.
3. Those **under 18** and **65 and over** are vulnerable to ozone and are, therefore, included. They should not be used as population denominators for disease estimates.
4. **Pediatric asthma** estimates are for those under 18 years of age and represent the **estimated** number of people who had asthma in 2018 based on state rates (BRFSS) applied to population estimates (U.S. Census).
5. **Adult asthma** estimates are for those 18 years and older and represent the **estimated** number of people who had asthma in 2018 based on state rates (BRFSS) applied to population estimates (U.S. Census).
6. Adding across rows does not produce valid estimates. Adding the disease categories (asthma, COPD, etc.) will double-count people who have been diagnosed with more than one disease.
7. **COPD** estimates are for adults 18 and over who have been diagnosed within their lifetime, based on state rates (BRFSS) applied to population estimates (U.S. Census).
8. **CV disease** is cardiovascular disease and estimates are for adults 18 and over who have been diagnosed within their lifetime, based on state rates (BRFSS) applied to population estimates (U.S. Census).
9. **People of color** are anyone of Hispanic ethnicity or a race other than white.
10. **Poverty** estimates come from the U.S. Census Bureau and are for all ages.
11. The **weighted average** was derived by counting the number of days in each unhealthful range (orange, red, purple) in each year (2016-2018), multiplying the total in each range by the assigned standard weights (i.e., 1 for orange, 1.5 for red, 2.0 for purple), and calculating the average.
12. **Grade** is assigned by weighted average as follows: A=0.0, B=0.3-0.9, C=1.0-2.0, D=2.1-3.2, F=3.3+.

Potential Water Savings from Arizona Solar Electricity Generation

Key Points

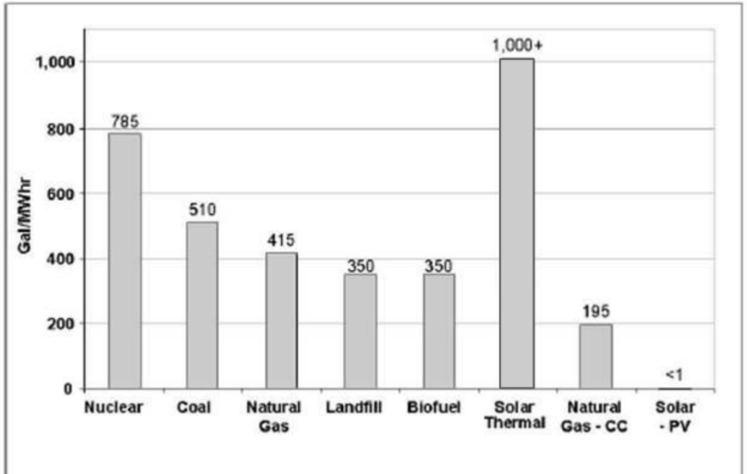
- Many forms of electricity production require water to function.
- Increasing the amount of solar PV could dramatically reduce the amount of water utilized in the state annually
- **Current savings = ~3 billion gallons of water annually**
- **Potential savings = ~ 50 billion gallons of water annually**
  - **Enough for ~ 1 million people annually**
- **Replacing all coal energy production with PV could save water equivalent to 16 Tempe Town Lakes annually**
- Compensating residential solar owners for the value of the water saved could provide incentives worth tens of millions of dollars

Water-Dependent Electricity in Arizona

Sources of Water-Dependent Electricity

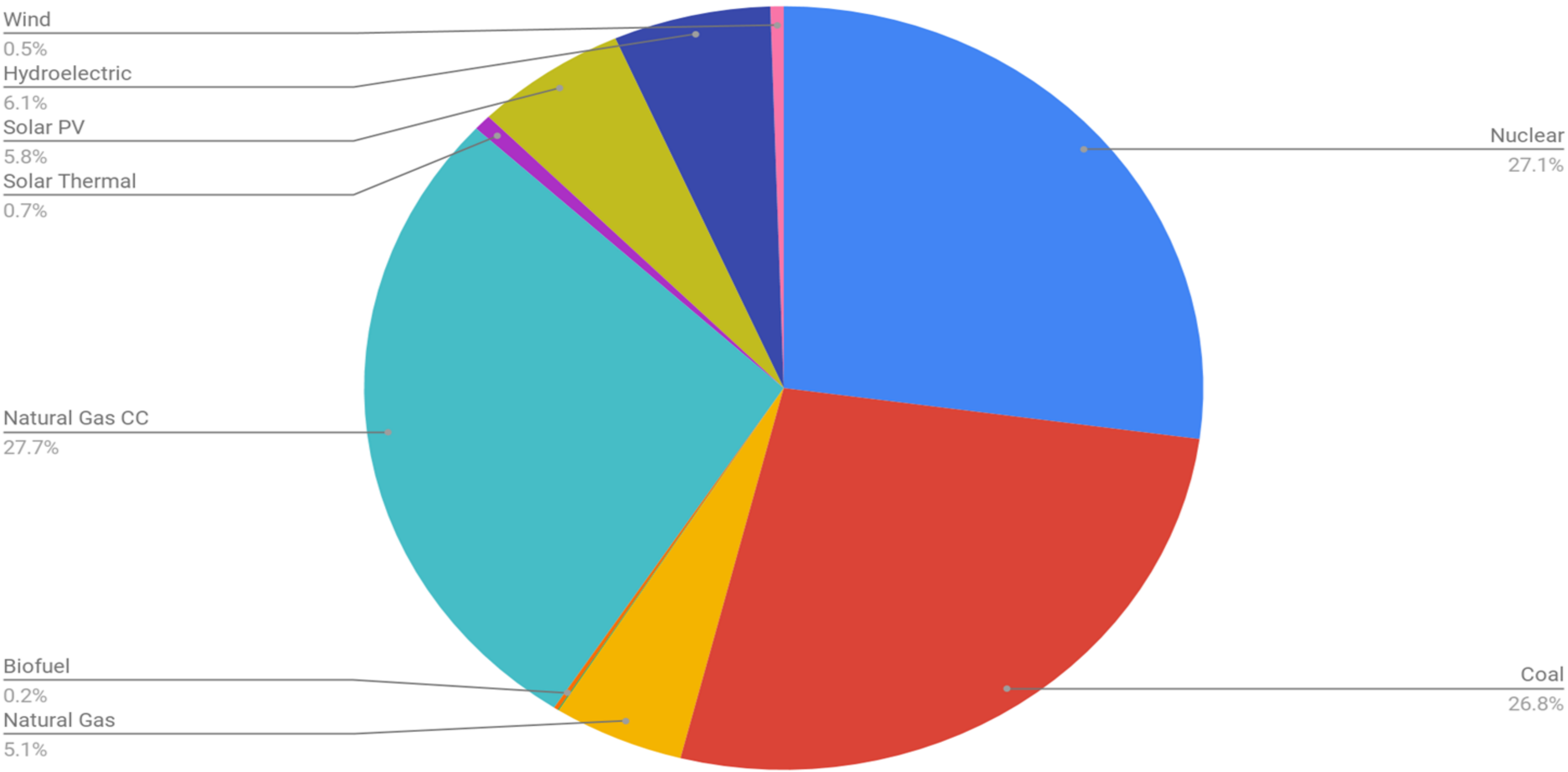
- Nuclear
- Coal
- Natural Gas
- Natural Gas CC
- Landfill
- Biofuel
- Solar Thermal

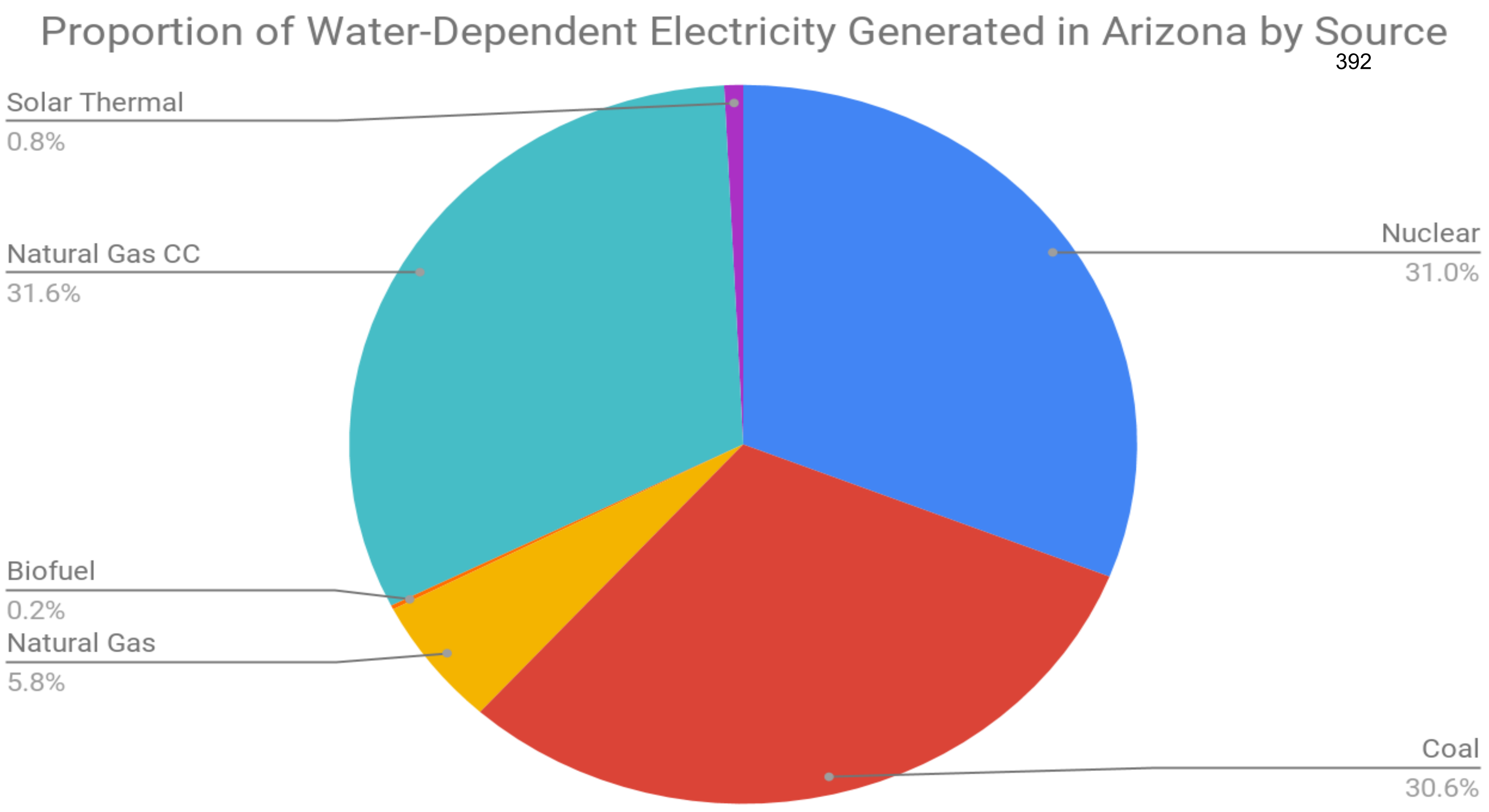
FIGURE 2.[59] **Average water consumption for electrical power generating facilities supplying Arizona.**[60] (*Note: The actual value for the single, 1 MW, experimental, concentrating solar power facility in Arizona is 311 gal/MWh, but this is seen as unrepresentative of the true water obligations of solar-trough technology. More realistic values, based on experience in California and discussion with industry representatives, is at least 1,000 gal/MWh, unless dry-cooling is employed.*)



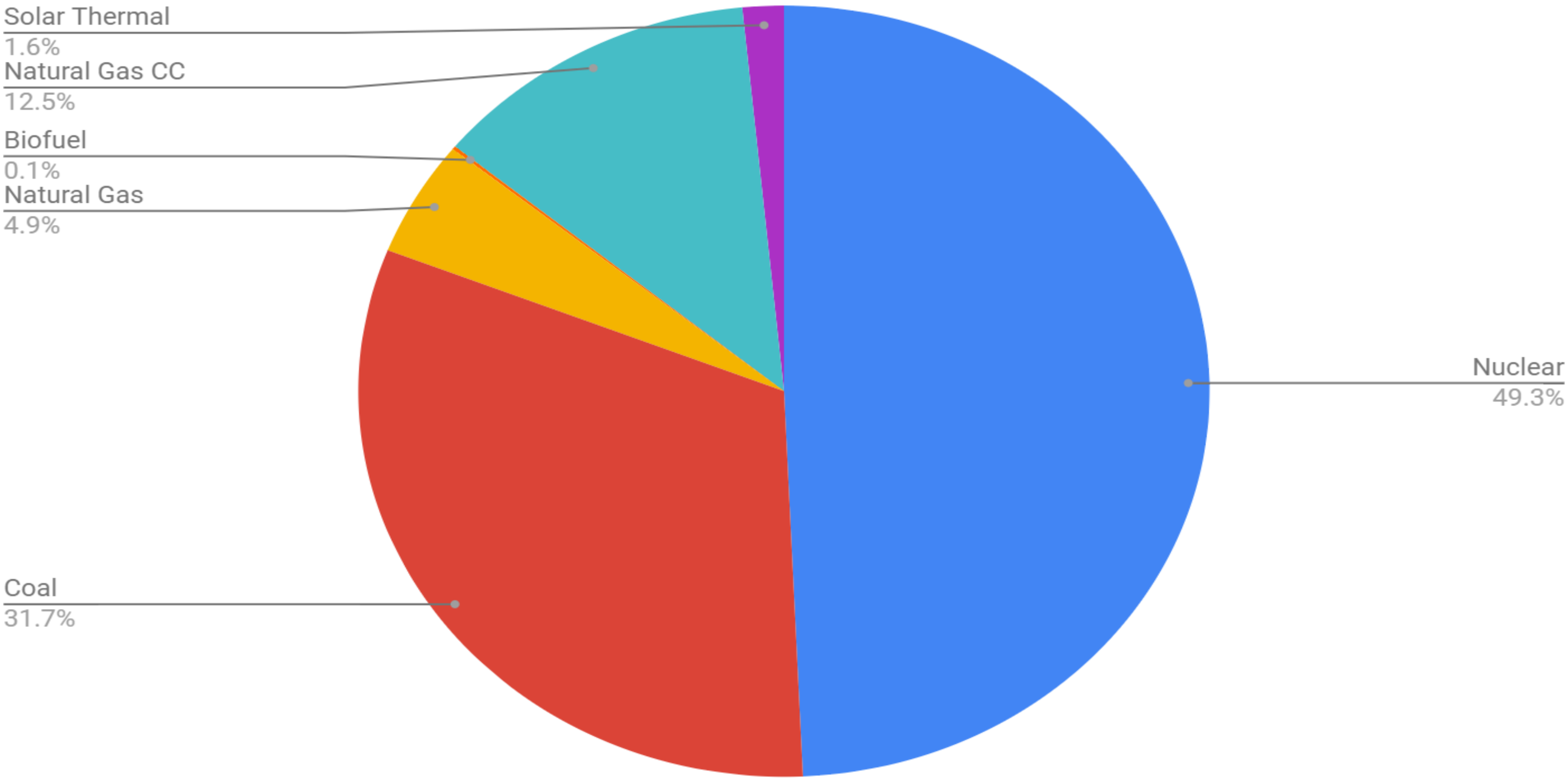
(Pasqualetti and Scott, 2010)

Total Electricity Generated in Arizona by Source




Proportion of Water-Dependent Electricity Generated in Arizona by Source
Solar Thermal
0.8%
Natural Gas CC
31.6%
Biofuel
0.2%
Natural Gas
5.8%
Nuclear
31.0%
Coal
30.6%

Proportion of Water Used by Water-Dependent Sources of Electricity in Arizona



Water Used Per Unit of Electricity Generated

- Estimated Total Annual Water-Dependent Electricity Generation (MWh) = ~ 100 million MWh
- Estimated Annual Water Usage from electric power systems (Gallons) = ~ 50 billion Gallons (~152,000 acre-feet)*
- **Total Annual Gallons Used per MWh of Electricity Generated = ~500 Gallons/MWh**

Annual Water Savings from Widespread Solar Adoption

- If a percentage of Arizona houses adopt solar
  - 25% - 4 billion gallons (12,000 acre-feet)
  - 50% - 8 billion gallons (26,000 acre-feet)
  - 100% - 18 billion gallons (54,000 acre-feet)
- If solar becomes a certain percentage of all generation
  - 25% - 11 billion gallons (33,000 acre-feet)
  - 50% - 25 billion gallons (77,000 acre-feet)
  - 100% - 50 billion gallons (152,000 acre-feet)

Annual Monetary Savings* from Widespread Solar Adoption

- If a percentage of houses adopt solar
  - 25% - 26 million dollars
  - 50% - 58 million dollars
  - 100% - 121 million dollars
- If solar becomes a certain percentage of all generation
  - 25% - 74 million dollars
  - 50% - 171 million dollars
  - 100% - 339 million dollars

*Assuming that all water saved is raw water

Overall Conclusions

- Solar PV generation saves significant amounts of water compared to other sources
  - Currently is saving 3.3 billion gallons annually
- Additional solar PV would generate substantial savings
  - Potentially billions of gallons and hundreds of millions of dollars annually (up to 3 Tempe's worth of water)
- Providing a water savings rebate according to the highest reasonable value of the water rewards solar customers
  - would increase with water prices and addition of other economic value
- Replacing all coal with solar could save huge amounts of water
  - Equivalent to 16 Tempe Town Lakes annually

Transmission and Regional Coordination

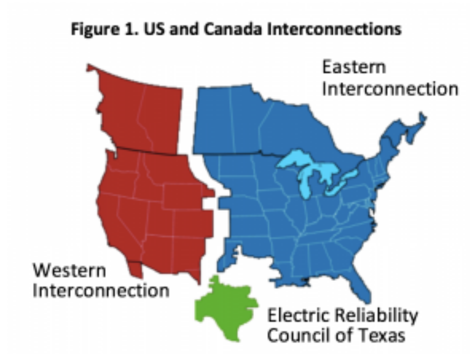
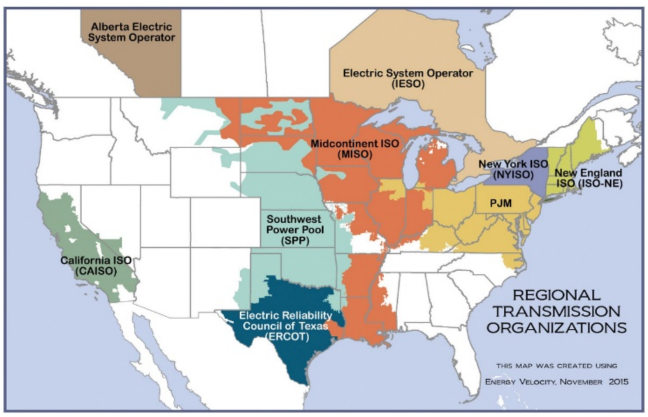


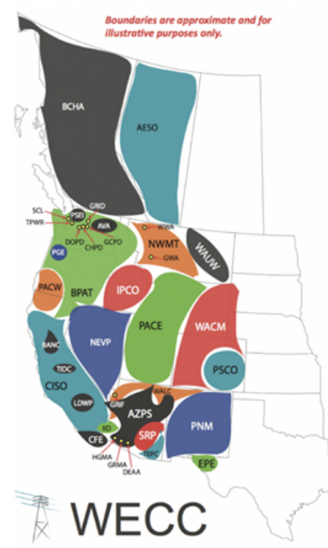
Figure 1. US and Canada Interconnections

The high voltage transmission system, comprised of all or portions of 14 western states, two Canadian provinces, and a small portion of Baja California in Mexico is known as the Western Interconnection. These areas are all physically, electrically interconnected. Thus, solar produced in Arizona can be delivered anywhere in the region, if there is sufficient transmission availability.



In most of the U.S. and the world, utilities work in concert to improve efficiency by sharing energy resources, collaboratively planning transmission expansion, and coordinating operation of the high voltage power grid to ensure adequate power to all areas at all times. This "organized market" construct is commonly called a Regional Transmission System (RTO) or Independent System Operator (ISO) as it serves the needs of utilities to manage power flows. The West and the Southeast are the only areas of the country that do not have organized markets (white areas on the map). The only organized part of the Western Interconnection is the California Independent System Operator.

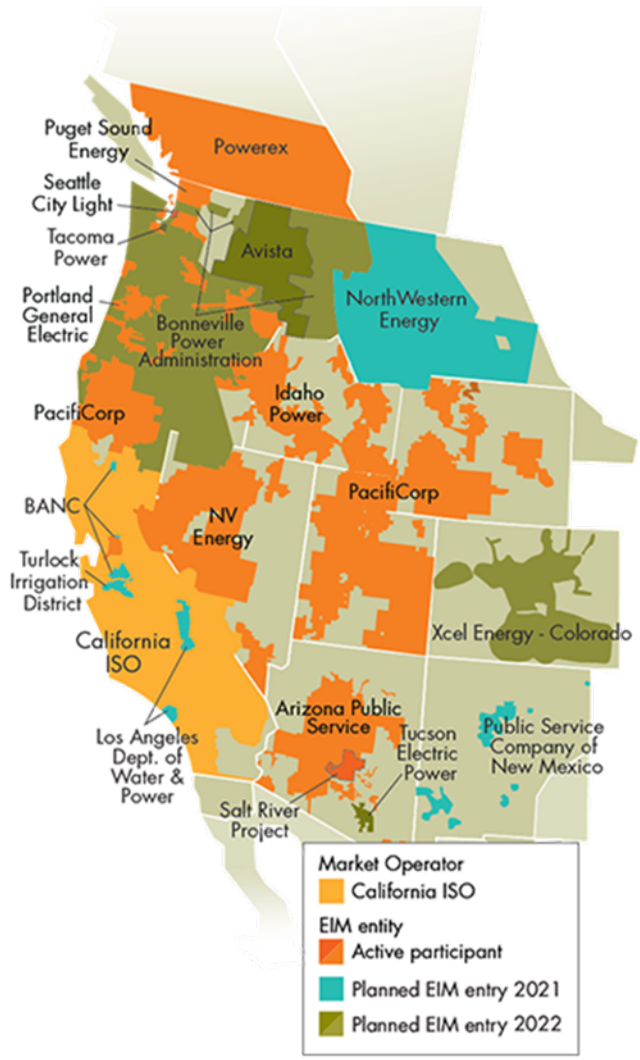
Most of the country's utilities have chosen to create and operate in RTOs to reduce costs and improve reliability for customers. While there have been several attempts to create a regional market in the west they have not succeeded. Instead, 39 different entities are responsible for managing electricity. These Balancing Authorities (typically, but not always, utilities) are each responsible for ensuring that the amount of electricity generation delivered to the grid is equal to the demand for electricity consumption at every moment. Since sharing of electric resources, planning for transmission and operating the high voltage system is limited or impossible in this balkanized system, costs are higher than necessary, and reliability suffers.



Source: Western Electricity Coordinating Council

The most recent effort of utilities to build an organized regional market started in 2012 when PacifiCorp (a utility that operates in seven states) agreed to participate in a voluntary sharing program for short term energy needs. This market platform, known as the Energy Imbalance Market (EIM), allows participating utilities to buy and sell energy they need to keep their systems in balance. Utilities offer excess energy to the market, as well as purchase energy that is less expensive than its own energy.

The EIM has been a huge success. As of July 2020, participating utilities have saved its customers one billion dollars (as documented by the CAISO, the operator of the platform). In addition, utilities have modernized their transmission system as joining the EIM required new hardware and software and operator training -- investments needed to adapt to changes in generation technology.



While the EIM has provided financial benefits and improved reliability, the energy traded in the platform is only a small percentage (~5%) of overall trades. Expanding the market to include more trading will provide additional financial benefits.

RTOs provide many services and benefits to utilities and their customers. Most important among them are:

- Reducing the amount of expensive "reserves" – excess energy maintained by utilities in case of a problem.
- Improving reliability through increased information sharing to spot and avoid disturbances, as well as having access to energy from other market participants when there is a disturbance.
- Smoothing variability of wind and solar resources through sharing.
- Efficiency gained from joint planning.

Utilities are considering more services and sharing toward a full RTO; however, progress has been slow. This is problematic as delay means customers are paying more for utility service than necessary, estimated to be in the millions of dollars per year per utility. As illustration, APS saved $6.4 million in the second quarter of 2020 as a result of participation in the EIM, a small part of an overall market. Stated another way, had APS not joined the EIM customers would have been charged $2 million dollars per month more for electric service. Efforts to ensure an RTO is built and joined as soon as possible will lower electric costs for customers.

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Summary for Policymakers

SPM

Introduction

This Report responds to the invitation for IPCC '... to provide a Special Report in 2018 on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways' contained in the Decision of the 21st Conference of Parties of the United Nations Framework Convention on Climate Change to adopt the Paris Agreement.[1]

The IPCC accepted the invitation in April 2016, deciding to prepare this Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty.

This Summary for Policymakers (SPM) presents the key findings of the Special Report, based on the assessment of the available scientific, technical and socio-economic literature[2] relevant to global warming of 1.5°C and for the comparison between global warming of 1.5°C and 2°C above pre-industrial levels. The level of confidence associated with each key finding is reported using the IPCC calibrated language.[3] The underlying scientific basis of each key finding is indicated by references provided to chapter elements. In the SPM, knowledge gaps are identified associated with the underlying chapters of the Report.

A. Understanding Global Warming of 1.5°C[4]

A.1 Human activities are estimated to have caused approximately 1.0°C of global warming[5] above pre-industrial levels, with a *likely* range of 0.8°C to 1.2°C. Global warming is *likely* to reach 1.5°C between 2030 and 2052 if it continues to increase at the current rate. (*high confidence*) (Figure SPM.1) {1.2}

A.1.1 Reflecting the long-term warming trend since pre-industrial times, observed global mean surface temperature (GMST) for the decade 2006–2015 was 0.87°C (*likely* between 0.75°C and 0.99°C)[6] higher than the average over the 1850–1900 period (*very high confidence*). Estimated anthropogenic global warming matches the level of observed warming to within ±20% (*likely range*). Estimated anthropogenic global warming is currently increasing at 0.2°C (*likely* between 0.1°C and 0.3°C) per decade due to past and ongoing emissions (*high confidence*). {1.2.1, Table 1.1, 1.2.4}

A.1.2 Warming greater than the global annual average is being experienced in many land regions and seasons, including two to three times higher in the Arctic. Warming is generally higher over land than over the ocean. (*high confidence*) {1.2.1, 1.2.2, Figure 1.1, Figure 1.3, 3.3.1, 3.3.2}

A.1.3 Trends in intensity and frequency of some climate and weather extremes have been detected over time spans during which about 0.5°C of global warming occurred (*medium confidence*). This assessment is based on several lines of evidence, including attribution studies for changes in extremes since 1950. {3.3.1, 3.3.2, 3.3.3}

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1 Decision 1/CP.21, paragraph 21.

2 The assessment covers literature accepted for publication by 15 May 2018.

3 Each finding is grounded in an evaluation of underlying evidence and agreement. A level of confidence is expressed using five qualifiers: very low, low, medium, high and very high, and typeset in italics, for example, *medium confidence*. The following terms have been used to indicate the assessed likelihood of an outcome or a result: virtually certain 99–100% probability, very likely 90–100%, likely 66–100%, about as likely as not 33–66%, unlikely 0–33%, very unlikely 0–10%, exceptionally unlikely 0–1%. Additional terms (extremely likely 95–100%, more likely than not >50–100%, more unlikely than likely 0–<50%, extremely unlikely 0–5%) may also be used when appropriate. Assessed likelihood is typeset in italics, for example, *very likely*. This is consistent with AR5.

4 See also Box SPM.1: Core Concepts Central to this Special Report.

5 Present level of global warming is defined as the average of a 30-year period centred on 2017 assuming the recent rate of warming continues.

6 This range spans the four available peer-reviewed estimates of the observed GMST change and also accounts for additional uncertainty due to possible short-term natural variability. {1.2.1, Table 1.1}

A.2 Warming from anthropogenic emissions from the pre-industrial period to the present will persist for centuries to millennia and will continue to cause further long-term changes in the climate system, such as sea level rise, with associated impacts (*high confidence*), but these emissions alone are *unlikely* to cause global warming of 1.5°C (*medium confidence*). (Figure SPM.1) {1.2, 3.3, Figure 1.5}

A.2.1 Anthropogenic emissions (including greenhouse gases, aerosols and their precursors) up to the present are *unlikely* to cause further warming of more than 0.5°C over the next two to three decades (*high confidence*) or on a century time scale (*medium confidence*). {1.2.4, Figure 1.5}

A.2.2 Reaching and sustaining net zero global anthropogenic CO_2 emissions and declining net non-CO_2 radiative forcing would halt anthropogenic global warming on multi-decadal time scales (*high confidence*). The maximum temperature reached is then determined by cumulative net global anthropogenic CO_2 emissions up to the time of net zero CO_2 emissions (*high confidence*) and the level of non-CO_2 radiative forcing in the decades prior to the time that maximum temperatures are reached (*medium confidence*). On longer time scales, sustained net negative global anthropogenic CO_2 emissions and/or further reductions in non-CO_2 radiative forcing may still be required to prevent further warming due to Earth system feedbacks and to reverse ocean acidification (*medium confidence*) and will be required to minimize sea level rise (*high confidence*). {Cross-Chapter Box 2 in Chapter 1, 1.2.3, 1.2.4, Figure 1.4, 2.2.1, 2.2.2, 3.4.4.8, 3.4.5.1, 3.6.3.2}

A.3 Climate-related risks for natural and human systems are higher for global warming of 1.5°C than at present, but lower than at 2°C (*high confidence*). These risks depend on the magnitude and rate of warming, geographic location, levels of development and vulnerability, and on the choices and implementation of adaptation and mitigation options (*high confidence*). (Figure SPM.2) {1.3, 3.3, 3.4, 5.6}

A.3.1 Impacts on natural and human systems from global warming have already been observed (*high confidence*). Many land and ocean ecosystems and some of the services they provide have already changed due to global warming (*high confidence*). (Figure SPM.2) {1.4, 3.4, 3.5}

A.3.2 Future climate-related risks depend on the rate, peak and duration of warming. In the aggregate, they are larger if global warming exceeds 1.5°C before returning to that level by 2100 than if global warming gradually stabilizes at 1.5°C, especially if the peak temperature is high (e.g., about 2°C) (*high confidence*). Some impacts may be long-lasting or irreversible, such as the loss of some ecosystems (*high confidence*). {3.2, 3.4.4, 3.6.3, Cross-Chapter Box 8 in Chapter 3}

A.3.3 Adaptation and mitigation are already occurring (*high confidence*). Future climate-related risks would be reduced by the upscaling and acceleration of far-reaching, multilevel and cross-sectoral climate mitigation and by both incremental and transformational adaptation (*high confidence*). {1.2, 1.3, Table 3.5, 4.2.2, Cross-Chapter Box 9 in Chapter 4, Box 4.2, Box 4.3, Box 4.6, 4.3.1, 4.3.2, 4.3.3, 4.3.4, 4.3.5, 4.4.1, 4.4.4, 4.4.5, 4.5.3}

Cumulative emissions of CO_2 and future non-CO_2 radiative forcing determine the probability of limiting warming to 1.5°C

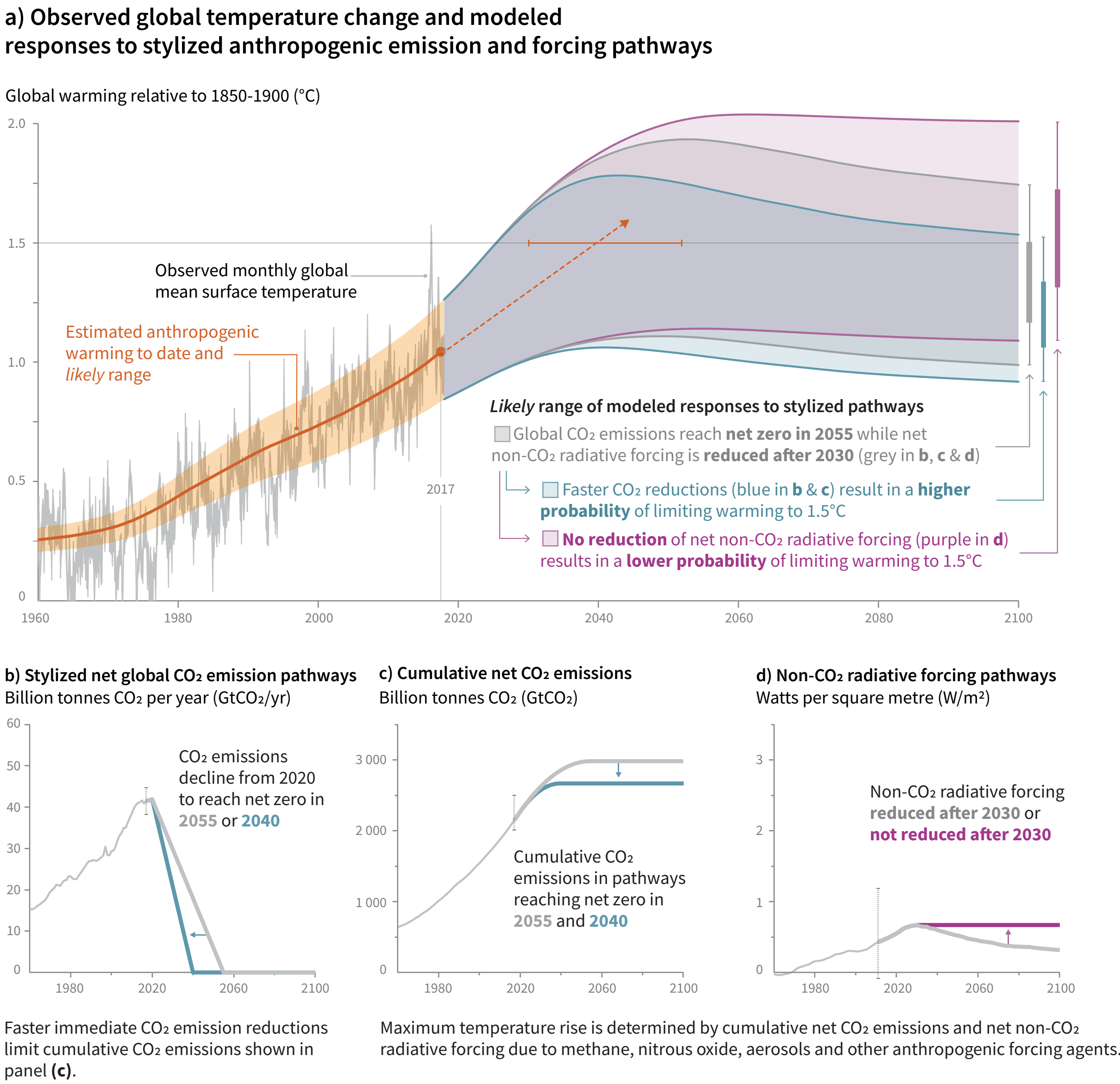

Figure SPM.1 | Panel a: Observed monthly global mean surface temperature (GMST, grey line up to 2017, from the HadCRUT4, GISTEMP, Cowtan–Way, and NOAA datasets) change and estimated anthropogenic global warming (solid orange line up to 2017, with orange shading indicating assessed *likely* range). Orange dashed arrow and horizontal orange error bar show respectively the central estimate and *likely* range of the time at which 1.5°C is reached if the current rate of warming continues. The grey plume on the right of panel a shows the *likely* range of warming responses, computed with a simple climate model, to a stylized pathway (hypothetical future) in which net CO_2 emissions (grey line in panels b and c) decline in a straight line from 2020 to reach net zero in 2055 and net non-CO_2 radiative forcing (grey line in panel d) increases to 2030 and then declines. The blue plume in panel a) shows the response to faster CO_2 emissions reductions (blue line in panel b), reaching net zero in 2040, reducing cumulative CO_2 emissions (panel c). The purple plume shows the response to net CO_2 emissions declining to zero in 2055, with net non-CO_2 forcing remaining constant after 2030. The vertical error bars on right of panel a) show the *likely* ranges (thin lines) and central terciles (33rd – 66th percentiles, thick lines) of the estimated distribution of warming in 2100 under these three stylized pathways. Vertical dotted error bars in panels b, c and d show the *likely* range of historical annual and cumulative global net CO_2 emissions in 2017 (data from the Global Carbon Project) and of net non-CO_2 radiative forcing in 2011 from AR5, respectively. Vertical axes in panels c and d are scaled to represent approximately equal effects on GMST. {1.2.1, 1.2.3, 1.2.4, 2.3, Figure 1.2 and Chapter 1 Supplementary Material, Cross-Chapter Box 2 in Chapter 1}

B. Projected Climate Change, Potential Impacts and Associated Risks

B.1 Climate models project robust[7] differences in regional climate characteristics between present-day and global warming of 1.5°C,[8] and between 1.5°C and 2°C.[8] These differences include increases in: mean temperature in most land and ocean regions (*high confidence*), hot extremes in most inhabited regions (*high confidence*), heavy precipitation in several regions (*medium confidence*), and the probability of drought and precipitation deficits in some regions (*medium confidence*). {3.3}

B.1.1 Evidence from attributed changes in some climate and weather extremes for a global warming of about 0.5°C supports the assessment that an additional 0.5°C of warming compared to present is associated with further detectable changes in these extremes (*medium confidence*). Several regional changes in climate are assessed to occur with global warming up to 1.5°C compared to pre-industrial levels, including warming of extreme temperatures in many regions (*high confidence*), increases in frequency, intensity, and/or amount of heavy precipitation in several regions (*high confidence*), and an increase in intensity or frequency of droughts in some regions (*medium confidence*). {3.2, 3.3.1, 3.3.2, 3.3.3, 3.3.4, Table 3.2}

B.1.2 Temperature extremes on land are projected to warm more than GMST (*high confidence*): extreme hot days in mid-latitudes warm by up to about 3°C at global warming of 1.5°C and about 4°C at 2°C, and extreme cold nights in high latitudes warm by up to about 4.5°C at 1.5°C and about 6°C at 2°C (*high confidence*). The number of hot days is projected to increase in most land regions, with highest increases in the tropics (*high confidence*). {3.3.1, 3.3.2, Cross-Chapter Box 8 in Chapter 3}

B.1.3 Risks from droughts and precipitation deficits are projected to be higher at 2°C compared to 1.5°C of global warming in some regions (*medium confidence*). Risks from heavy precipitation events are projected to be higher at 2°C compared to 1.5°C of global warming in several northern hemisphere high-latitude and/or high-elevation regions, eastern Asia and eastern North America (*medium confidence)*. Heavy precipitation associated with tropical cyclones is projected to be higher at 2°C compared to 1.5°C global warming (*medium confidence*). There is generally *low confidence* in projected changes in heavy precipitation at 2°C compared to 1.5°C in other regions. Heavy precipitation when aggregated at global scale is projected to be higher at 2°C than at 1.5°C of global warming (*medium confidence*). As a consequence of heavy precipitation, the fraction of the global land area affected by flood hazards is projected to be larger at 2°C compared to 1.5°C of global warming (*medium confidence*). {3.3.1, 3.3.3, 3.3.4, 3.3.5, 3.3.6}

B.2 By 2100, global mean sea level rise is projected to be around 0.1 metre lower with global warming of 1.5°C compared to 2°C (*medium confidence*). Sea level will continue to rise well beyond 2100 (*high confidence*), and the magnitude and rate of this rise depend on future emission pathways. A slower rate of sea level rise enables greater opportunities for adaptation in the human and ecological systems of small islands, low-lying coastal areas and deltas (*medium confidence*). {3.3, 3.4, 3.6}

B.2.1 Model-based projections of global mean sea level rise (relative to 1986–2005) suggest an indicative range of 0.26 to 0.77 m by 2100 for 1.5°C of global warming, 0.1 m (0.04–0.16 m) less than for a global warming of 2°C (*medium confidence*). A reduction of 0.1 m in global sea level rise implies that up to 10 million fewer people would be exposed to related risks, based on population in the year 2010 and assuming no adaptation (*medium confidence*). {3.4.4, 3.4.5, 4.3.2}

B.2.2 Sea level rise will continue beyond 2100 even if global warming is limited to 1.5°C in the 21st century (*high confidence*). Marine ice sheet instability in Antarctica and/or irreversible loss of the Greenland ice sheet could result in multi-metre rise in sea level over hundreds to thousands of years. These instabilities could be triggered at around 1.5°C to 2°C of global warming (*medium confidence*). (Figure SPM.2) {3.3.9, 3.4.5, 3.5.2, 3.6.3, Box 3.3}

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7 Robust is here used to mean that at least two thirds of climate models show the same sign of changes at the grid point scale, and that differences in large regions are statistically significant.

8 Projected changes in impacts between different levels of global warming are determined with respect to changes in global mean surface air temperature.

B.2.3 Increasing warming amplifies the exposure of small islands, low-lying coastal areas and deltas to the risks associated with sea level rise for many human and ecological systems, including increased saltwater intrusion, flooding and damage to infrastructure (*high confidence*). Risks associated with sea level rise are higher at 2°C compared to 1.5°C. The slower rate of sea level rise at global warming of 1.5°C reduces these risks, enabling greater opportunities for adaptation including managing and restoring natural coastal ecosystems and infrastructure reinforcement (*medium confidence*). (Figure SPM.2) {3.4.5, Box 3.5}

B.3 On land, impacts on biodiversity and ecosystems, including species loss and extinction, are projected to be lower at 1.5°C of global warming compared to 2°C. Limiting global warming to 1.5°C compared to 2°C is projected to lower the impacts on terrestrial, freshwater and coastal ecosystems and to retain more of their services to humans (*high confidence*). (Figure SPM.2) {3.4, 3.5, Box 3.4, Box 4.2, Cross-Chapter Box 8 in Chapter 3}

B.3.1 Of 105,000 species studied,[9] 6% of insects, 8% of plants and 4% of vertebrates are projected to lose over half of their climatically determined geographic range for global warming of 1.5°C, compared with 18% of insects, 16% of plants and 8% of vertebrates for global warming of 2°C (*medium confidence*). Impacts associated with other biodiversity-related risks such as forest fires and the spread of invasive species are lower at 1.5°C compared to 2°C of global warming (*high confidence*). {3.4.3, 3.5.2}

B.3.2 Approximately 4% (interquartile range 2–7%) of the global terrestrial land area is projected to undergo a transformation of ecosystems from one type to another at 1°C of global warming, compared with 13% (interquartile range 8–20%) at 2°C (*medium confidence*). This indicates that the area at risk is projected to be approximately 50% lower at 1.5°C compared to 2°C (*medium confidence*). {3.4.3.1, 3.4.3.5}

B.3.3 High-latitude tundra and boreal forests are particularly at risk of climate change-induced degradation and loss, with woody shrubs already encroaching into the tundra (*high confidence*) and this will proceed with further warming. Limiting global warming to 1.5°C rather than 2°C is projected to prevent the thawing over centuries of a permafrost area in the range of 1.5 to 2.5 million km^2 (*medium confidence*). {3.3.2, 3.4.3, 3.5.5}

B.4 Limiting global warming to 1.5°C compared to 2°C is projected to reduce increases in ocean temperature as well as associated increases in ocean acidity and decreases in ocean oxygen levels (*high confidence*). Consequently, limiting global warming to 1.5°C is projected to reduce risks to marine biodiversity, fisheries, and ecosystems, and their functions and services to humans, as illustrated by recent changes to Arctic sea ice and warm-water coral reef ecosystems (*high confidence*). {3.3, 3.4, 3.5, Box 3.4, Box 3.5}

B.4.1 There is *high confidence* that the probability of a sea ice-free Arctic Ocean during summer is substantially lower at global warming of 1.5°C when compared to 2°C. With 1.5°C of global warming, one sea ice-free Arctic summer is projected per century. This likelihood is increased to at least one per decade with 2°C global warming. Effects of a temperature overshoot are reversible for Arctic sea ice cover on decadal time scales (*high confidence*). {3.3.8, 3.4.4.7}

B.4.2 Global warming of 1.5°C is projected to shift the ranges of many marine species to higher latitudes as well as increase the amount of damage to many ecosystems. It is also expected to drive the loss of coastal resources and reduce the productivity of fisheries and aquaculture (especially at low latitudes). The risks of climate-induced impacts are projected to be higher at 2°C than those at global warming of 1.5°C (*high confidence*). Coral reefs, for example, are projected to decline by a further 70–90% at 1.5°C (*high confidence*) with larger losses (>99%) at 2°C (*very high confidence*). The risk of irreversible loss of many marine and coastal ecosystems increases with global warming, especially at 2°C or more (*high confidence*). {3.4.4, Box 3.4}

9 Consistent with earlier studies, illustrative numbers were adopted from one recent meta-study.

B.4.3 The level of ocean acidification due to increasing CO_2 concentrations associated with global warming of 1.5°C is projected to amplify the adverse effects of warming, and even further at 2°C, impacting the growth, development, calcification, survival, and thus abundance of a broad range of species, for example, from algae to fish (*high confidence*). {3.3.10, 3.4.4}

B.4.4 Impacts of climate change in the ocean are increasing risks to fisheries and aquaculture via impacts on the physiology, survivorship, habitat, reproduction, disease incidence, and risk of invasive species (*medium confidence*) but are projected to be less at 1.5°C of global warming than at 2°C. One global fishery model, for example, projected a decrease in global annual catch for marine fisheries of about 1.5 million tonnes for 1.5°C of global warming compared to a loss of more than 3 million tonnes for 2°C of global warming (*medium confidence*). {3.4.4, Box 3.4}

B.5 Climate-related risks to health, livelihoods, food security, water supply, human security, and economic growth are projected to increase with global warming of 1.5°C and increase further with 2°C. (Figure SPM.2) {3.4, 3.5, 5.2, Box 3.2, Box 3.3, Box 3.5, Box 3.6, Cross-Chapter Box 6 in Chapter 3, Cross-Chapter Box 9 in Chapter 4, Cross-Chapter Box 12 in Chapter 5, 5.2}

B.5.1 Populations at disproportionately higher risk of adverse consequences with global warming of 1.5°C and beyond include disadvantaged and vulnerable populations, some indigenous peoples, and local communities dependent on agricultural or coastal livelihoods (*high confidence*). Regions at disproportionately higher risk include Arctic ecosystems, dryland regions, small island developing states, and Least Developed Countries (*high confidence*). Poverty and disadvantage are expected to increase in some populations as global warming increases; limiting global warming to 1.5°C, compared with 2°C, could reduce the number of people both exposed to climate-related risks and susceptible to poverty by up to several hundred million by 2050 (*medium confidence*). {3.4.10, 3.4.11, Box 3.5, Cross-Chapter Box 6 in Chapter 3, Cross-Chapter Box 9 in Chapter 4, Cross-Chapter Box 12 in Chapter 5, 4.2.2.2, 5.2.1, 5.2.2, 5.2.3, 5.6.3}

B.5.2 Any increase in global warming is projected to affect human health, with primarily negative consequences (*high confidence*). Lower risks are projected at 1.5°C than at 2°C for heat-related morbidity and mortality (*very high confidence*) and for ozone-related mortality if emissions needed for ozone formation remain high (*high confidence*). Urban heat islands often amplify the impacts of heatwaves in cities (*high confidence*). Risks from some vector-borne diseases, such as malaria and dengue fever, are projected to increase with warming from 1.5°C to 2°C, including potential shifts in their geographic range (*high confidence*). {3.4.7, 3.4.8, 3.5.5.8}

B.5.3 Limiting warming to 1.5°C compared with 2°C is projected to result in smaller net reductions in yields of maize, rice, wheat, and potentially other cereal crops, particularly in sub-Saharan Africa, Southeast Asia, and Central and South America, and in the CO_2-dependent nutritional quality of rice and wheat (*high confidence*). Reductions in projected food availability are larger at 2°C than at 1.5°C of global warming in the Sahel, southern Africa, the Mediterranean, central Europe, and the Amazon (*medium confidence*). Livestock are projected to be adversely affected with rising temperatures, depending on the extent of changes in feed quality, spread of diseases, and water resource availability (*high confidence*). {3.4.6, 3.5.4, 3.5.5, Box 3.1, Cross-Chapter Box 6 in Chapter 3, Cross-Chapter Box 9 in Chapter 4}

B.5.4 Depending on future socio-economic conditions, limiting global warming to 1.5°C compared to 2°C may reduce the proportion of the world population exposed to a climate change-induced increase in water stress by up to 50%, although there is considerable variability between regions (*medium confidence*). Many small island developing states could experience lower water stress as a result of projected changes in aridity when global warming is limited to 1.5°C, as compared to 2°C (*medium confidence*). {3.3.5, 3.4.2, 3.4.8, 3.5.5, Box 3.2, Box 3.5, Cross-Chapter Box 9 in Chapter 4}

B.5.5 Risks to global aggregated economic growth due to climate change impacts are projected to be lower at 1.5°C than at 2°C by the end of this century[10] (*medium confidence*). This excludes the costs of mitigation, adaptation investments and the benefits of adaptation. Countries in the tropics and Southern Hemisphere subtropics are projected to experience the largest impacts on economic growth due to climate change should global warming increase from 1.5°C to 2°C (*medium confidence*). {3.5.2, 3.5.3}

10 Here, impacts on economic growth refer to changes in gross domestic product (GDP). Many impacts, such as loss of human lives, cultural heritage and ecosystem services, are difficult to value and monetize.

B.5.6 Exposure to multiple and compound climate-related risks increases between 1.5°C and 2°C of global warming, with greater proportions of people both so exposed and susceptible to poverty in Africa and Asia (*high confidence*). For global warming from 1.5°C to 2°C, risks across energy, food, and water sectors could overlap spatially and temporally, creating new and exacerbating current hazards, exposures, and vulnerabilities that could affect increasing numbers of people and regions (*medium confidence*). {Box 3.5, 3.3.1, 3.4.5.3, 3.4.5.6, 3.4.11, 3.5.4.9}

B.5.7 There are multiple lines of evidence that since AR5 the assessed levels of risk increased for four of the five Reasons for Concern (RFCs) for global warming to 2°C (*high confidence*). The risk transitions by degrees of global warming are now: from high to very high risk between 1.5°C and 2°C for RFC1 (Unique and threatened systems) (*high confidence*); from moderate to high risk between 1°C and 1.5°C for RFC2 (Extreme weather events) (*medium confidence*); from moderate to high risk between 1.5°C and 2°C for RFC3 (Distribution of impacts) (*high confidence*); from moderate to high risk between 1.5°C and 2.5°C for RFC4 (Global aggregate impacts) (*medium confidence*); and from moderate to high risk between 1°C and 2.5°C for RFC5 (Large-scale singular events) (*medium confidence*). (Figure SPM.2) {3.4.13; 3.5, 3.5.2}

B.6 Most adaptation needs will be lower for global warming of 1.5°C compared to 2°C (*high confidence*). There are a wide range of adaptation options that can reduce the risks of climate change (*high confidence*). There are limits to adaptation and adaptive capacity for some human and natural systems at global warming of 1.5°C, with associated losses (*medium confidence*). The number and availability of adaptation options vary by sector (*medium confidence*). {Table 3.5, 4.3, 4.5, Cross-Chapter Box 9 in Chapter 4, Cross-Chapter Box 12 in Chapter 5}

B.6.1 A wide range of adaptation options are available to reduce the risks to natural and managed ecosystems (e.g., ecosystem-based adaptation, ecosystem restoration and avoided degradation and deforestation, biodiversity management, sustainable aquaculture, and local knowledge and indigenous knowledge), the risks of sea level rise (e.g., coastal defence and hardening), and the risks to health, livelihoods, food, water, and economic growth, especially in rural landscapes (e.g., efficient irrigation, social safety nets, disaster risk management, risk spreading and sharing, and community-based adaptation) and urban areas (e.g., green infrastructure, sustainable land use and planning, and sustainable water management) (*medium confidence*). {4.3.1, 4.3.2, 4.3.3, 4.3.5, 4.5.3, 4.5.4, 5.3.2, Box 4.2, Box 4.3, Box 4.6, Cross-Chapter Box 9 in Chapter 4}.

B.6.2 Adaptation is expected to be more challenging for ecosystems, food and health systems at 2°C of global warming than for 1.5°C (*medium confidence*). Some vulnerable regions, including small islands and Least Developed Countries, are projected to experience high multiple interrelated climate risks even at global warming of 1.5°C (*high confidence*). {3.3.1, 3.4.5, Box 3.5, Table 3.5, Cross-Chapter Box 9 in Chapter 4, 5.6, Cross-Chapter Box 12 in Chapter 5, Box 5.3}

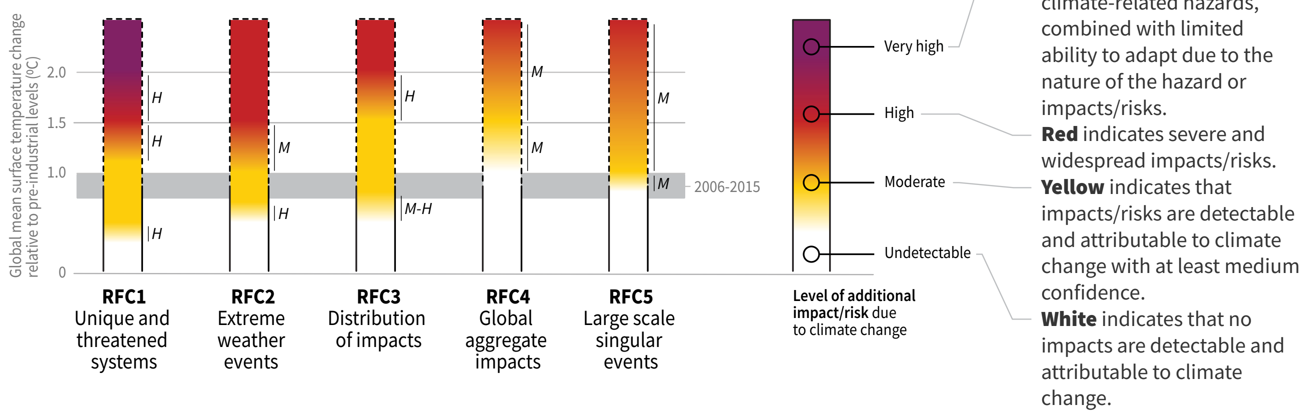
B.6.3 Limits to adaptive capacity exist at 1.5°C of global warming, become more pronounced at higher levels of warming and vary by sector, with site-specific implications for vulnerable regions, ecosystems and human health (*medium confidence*). {Cross-Chapter Box 12 in Chapter 5, Box 3.5, Table 3.5}

SPM

How the level of global warming affects impacts and/or risks associated with the Reasons for Concern (RFCs) and selected natural, managed and human systems

Five Reasons For Concern (RFCs) illustrate the impacts and risks of different levels of global warming for people, economies and ecosystems across sectors and regions.

Impacts and risks associated with the Reasons for Concern (RFCs)



Impacts and risks for selected natural, managed and human systems

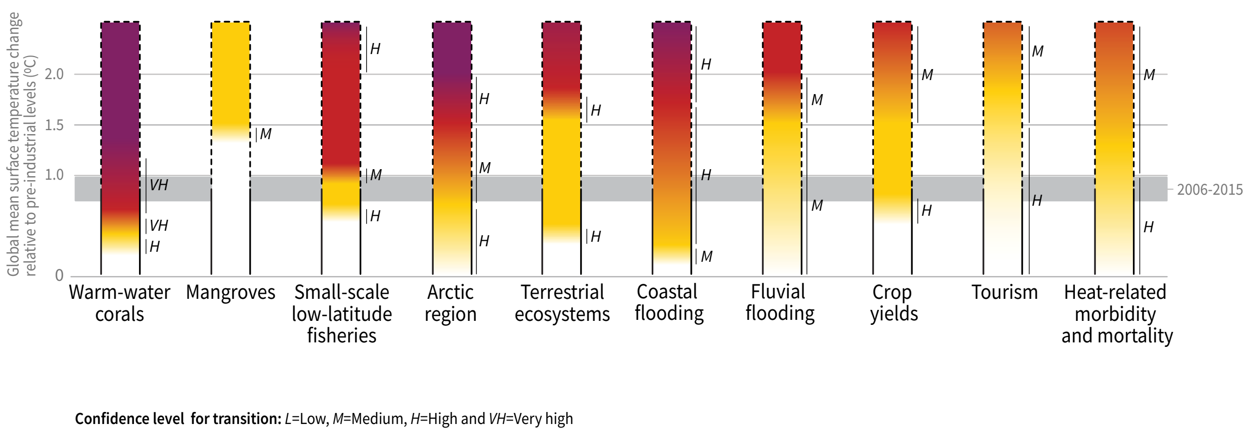


Figure SPM.2 | Five integrative reasons for concern (RFCs) provide a framework for summarizing key impacts and risks across sectors and regions, and were introduced in the IPCC Third Assessment Report. RFCs illustrate the implications of global warming for people, economies and ecosystems. Impacts and/or risks for each RFC are based on assessment of the new literature that has appeared. As in AR5, this literature was used to make expert judgments to assess the levels of global warming at which levels of impact and/or risk are undetectable, moderate, high or very high. The selection of impacts and risks to natural, managed and human systems in the lower panel is illustrative and is not intended to be fully comprehensive. {3.4, 3.5, 3.5.2.1, 3.5.2.2, 3.5.2.3, 3.5.2.4, 3.5.2.5, 5.4.1, 5.5.3, 5.6.1, Box 3.4}

RFC1 Unique and threatened systems: ecological and human systems that have restricted geographic ranges constrained by climate-related conditions and have high endemism or other distinctive properties. Examples include coral reefs, the Arctic and its indigenous people, mountain glaciers and biodiversity hotspots.

RFC2 Extreme weather events: risks/impacts to human health, livelihoods, assets and ecosystems from extreme weather events such as heat waves, heavy rain, drought and associated wildfires, and coastal flooding.

RFC3 Distribution of impacts: risks/impacts that disproportionately affect particular groups due to uneven distribution of physical climate change hazards, exposure or vulnerability.

RFC4 Global aggregate impacts: global monetary damage, global-scale degradation and loss of ecosystems and biodiversity.

RFC5 Large-scale singular events: are relatively large, abrupt and sometimes irreversible changes in systems that are caused by global warming. Examples include disintegration of the Greenland and Antarctic ice sheets.

Contacts Per Policy Area*

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